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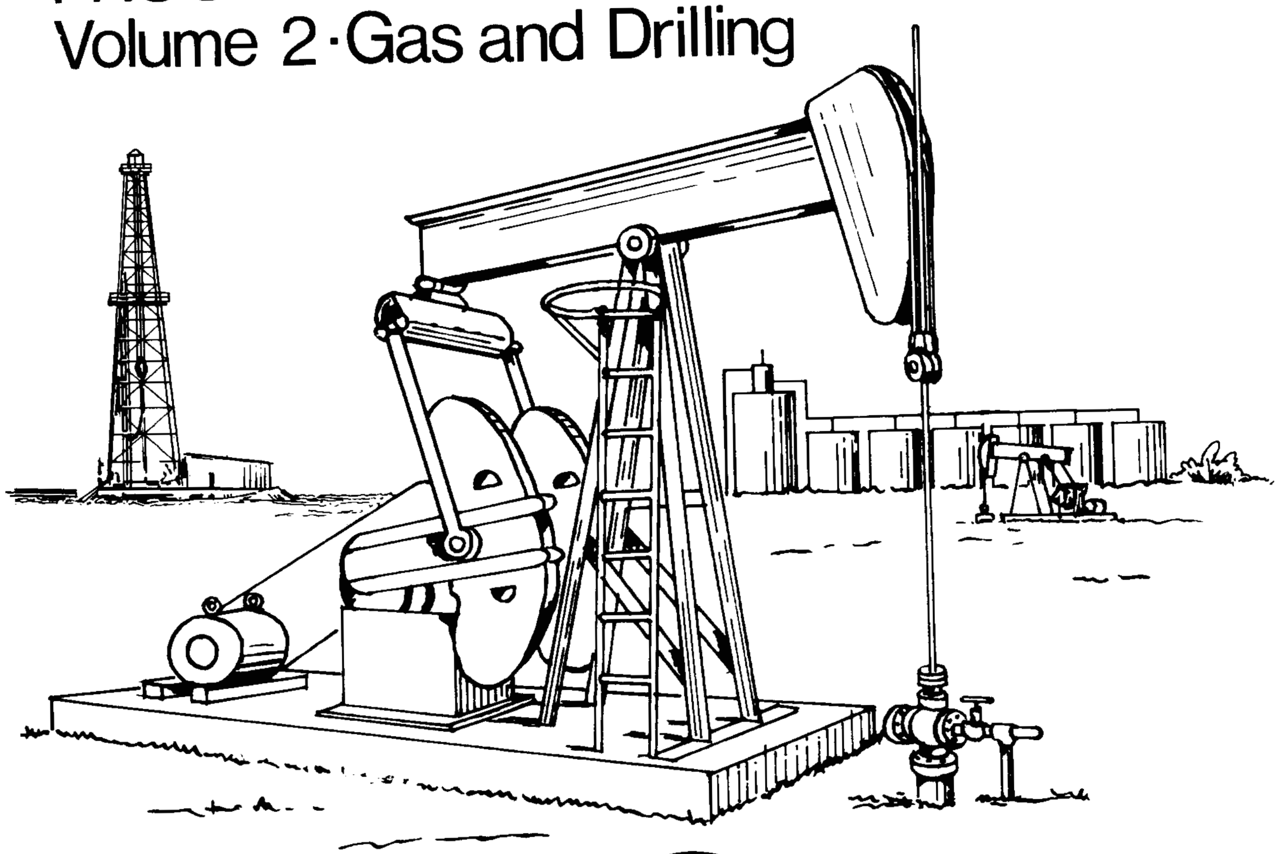

ERDA

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CAMELOT INN TULSA, OKLAHOMA

August 30-31—September 1, 1977

Energy Research and Development Administration

Division of Oil, Gas, and Shale Technology

IN COOPERATION WITH

UNIVERSITY of TULSA • OIL & GAS JOURNAL

The University of Tulsa

OIL & GAS JOURNAL

PROCEEDINGS

VOLUME 2 – GAS AND DRILLING

THIRD ERDA SYMPOSIUM ON ENHANCED OIL & GAS RECOVERY & IMPROVED DRILLING METHODS

Tulsa, Oklahoma, August 30–September 1, 1977

Bill Linville, *Editor*
Joe R. Lindley, *Illustrator*
Janet Whaling, *Editorial Assistant*
BARTLESVILLE ENERGY RESEARCH CENTER, BARTLESVILLE, OKLAHOMA

Contains papers for the following sessions

Session E–Enhanced Gas Recovery (Western)

Session F–Supporting Research for Enhanced Gas Recovery

Session G–Eastern Gas Shales

Session H–Drilling and Rock Mechanics

Volume 1–Oil, contains papers from

Session A–Micellar-Polymer Flooding

Session B–Improved Waterflooding

Session C–Carbon Dioxide Flooding

Session D–Thermal Methods/Heavy Oil

Published by
THE PETROLEUM PUBLISHING COMPANY
POST OFFICE BOX 1260, TULSA, OKLAHOMA 74101
Publisher of the Oil & Gas Journal

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GEOLOGICAL PROGRAM TO PROVIDE A CHARACTERIZATION OF TIGHT, GAS-BEARING RESERVOIRS IN THE ROCKY MOUNTAIN REGION

by

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ABSTRACT

In 1977, the U.S. Geological Survey, in cooperation with the Energy Research and Development Administration, initiated a geological program designed to characterize natural gas resources in low-permeability (tight) reservoirs in the Rocky Mountain region. These reservoirs are present from depths of less than 2,000 feet to greater than 19,000 feet. The U.S. Geological Survey is now studying the areas and rock units that have the best resource potential in the region. These are the tight sandstone and siltstone reservoirs of early Tertiary and Late Cretaceous age in the Uinta, Piceance, and Greater Green River Basins, and Upper Cretaceous sandstone, siltstone, shale, and marl reservoirs in the northern Great Plains. The Greater Green River Basin includes the Green River Basin proper, and the Washakie, Great Divide, and Sand Wash Basins. The gas potential of tight, offshore-marine deposits of the northern Great Plains was first recognized by D. D. Rice.

The purpose of the present investigation is to outline the distribution of low-permeability gas-bearing formations, characterize the reservoirs, assist in improving the recovery technology, and provide a refined estimate of in-place gas resources. The amount of recoverable gas is dependent on economic factors and advancements in recovery technology.

A wide variety of geological techniques is being used to resolve resource and recovery technology problems in tight gas sands. These techniques include studies in surface and subsurface stratigraphy, paleoenvironmental interpretation, geophysical borehole logging, computer processing of well history and geologic data, lineament analysis using earth-satellite imagery, scanning electron microscopy, X-ray diffraction and fluorescence, reservoir-rock petrography, pore-throat studies, core analysis, micropaleontology, organic geochemistry, thermal-maturation studies, borehole-gravimeter logging, subsurface-pressure mapping, and hydrodynamic analysis.

Prepared for the Energy Research and Development Administration, under Contract No. EY-76-A-08-0474, Modification No. M021.

Approximately 20 preliminary regional stratigraphic sections, prepared from electric logs and surface sections, have been constructed in order to properly correlate equivalent gas-bearing intervals. Many of the rock units being investigated are nonmarine deposits, which cannot be readily correlated without the aid of micropaleontology.

Petrographic studies of cores have shown that the distribution of clays in pore throats has a great influence on rock permeability. Many whole-rock clay-mineral analyses show that a variety of clay minerals are commonly present in a reservoir unit. However, when the SEM is used in conjunction with X-ray fluorescence, it can be shown that only one of the clays may be critical to permeability and stimulation problems. Lack of recognition of the distribution of clays in reservoir beds may account for some anomalous production test results.

INTRODUCTION

In 1977, the U.S. Geological Survey (USGS), in cooperation with the Energy Research and Development Administration (ERDA), initiated a geological program designed to characterize the natural gas resources in low permeability (tight) reservoirs in the Rocky Mountain region. This program is part of the ERDA Western Gas Sands Project and is concerned with presently noncommercial reservoir rocks of Late Cretaceous and early Tertiary age. These reservoirs are present from depths of less than 2,000 feet to greater than 19,000 feet. Figure 1 shows the location of study areas in the Uinta and Piceance Basins of northeastern Utah and northwestern Colorado, the Greater Green River Basin of southwestern Wyoming and northwestern Colorado, and the northern Great Plains of eastern Montana and western North and South Dakota. The geological characterization of reservoirs necessary for resource assessment should also provide worthwhile data for enhanced recovery research projects being supported by ERDA in the Rockies and elsewhere in the United States. Pertinent data from present and past recovery research will be integrated into the USGS investigation to avoid any duplication of effort.

SCOPE OF WORK

The work is subdivided into eight discrete categories of investigation that apply to the entire Rocky Mountain region; each also forms an integral part of the individual area studies. These fields of research are listed below, with a brief summary of the objectives and methods:

1. Stratigraphic and structural studies--Subsurface mapping, supplemented by some outcrop work, provides the basic framework for the entire program.

   Objectives:

   a. Map the distribution, geometry, thickness, and stratigraphic relations of the various producing and potentially productive tight reservoirs and their association with source rocks, using borehole logs, lithology logs, cores, and outcrop sections.

b. Map the regional structural framework of each area and its relationship to gas accumulation.
c. Interpret the paleogeography, sedimentary history, and depositional environments in order to determine lateral and vertical extent of reservoirs and to determine which settings and associated lithofacies are conducive to gas entrapment.
d. Determine trapping mechanisms, both stratigraphic and/or structural, including the possible influence of hydrodynamics.
e. Prepare maps of surface fractures using photos from earth satellites and aircraft.

Methods:

This investigation involves the study, analysis, and correlation of subsurface and surface rock samples, borehole logs, and fracture lineaments. This information will be placed in a data system and used to produce maps and cross sections, which will be combined with data derived from other studies in the program. In nonmarine sections, the time framework and correlations will be based on paleontologic data.

2. Geochemical studies--This predominantly analytical program will lead to an understanding of the fundamental processes that govern the origin(s) and distribution of natural gas in tight gas sands.

Objectives:

a. Identify the origin(s) of gases within a study area as related to the three main stages of hydrocarbon generation.
b. Predict time of gas generation and determine those subsurface strata in which maximum gas generation probably took place.
c. Identify and quantify potential source beds in strata described in "b" above to provide basic data for estimating the amounts of gas that should have been generated.
d. Map paleomigration pathways as a means of identifying regional focal areas of gas entrapment.

Concepts and methods:

Natural gas accumulations are related to different modes of origin within the generally recognized three stages of hydrocarbon generation: (1) Immature--biological processes acting at shallow depths in accumulating sediments cause generation of gas consisting chiefly of methane, (2) Mature--

thermal cracking processes generate liquid hydrocarbons (oil) and heavy molecular-weight gases, (3) Post-mature--gas, consisting chiefly of methane, is generated by the destruction of liquid hydrocarbons and heavier molecular-weight gases and by the conversion of organic matter to carbon-rich residues and volatile compounds in response to increasingly severe thermal cracking. Thermal cracking processes of the mature and post-mature stages are controlled by temperature and duration-of-heating (geologic time) factors. The immature stage is also indirectly controlled by thermal cracking processes because the biological activity, responsible for gas generation, is killed off by increasing temperature. The products of these stages can be distinguished by the hydrocarbon composition of natural gas and the carbon isotope ratios of the methane.

Once the type (origin) of natural gas for a given area is determined, it is possible to predict subsurface depths at which maximum generation of a particular type of gas would be expected. The organic matter in the rocks undergoes various changes resulting from a combination of temperature and geologic time factors. Levels of maturation can be determined by various geochemical and petrographic methods such as spore coloration, vitrinite reflectance, carbon-preference index, hydrocarbon percentage, ratio of hydrocarbon to organic carbon, hydrogen-to-carbon ratio of kerogen, and saturated-to-aromatic-hydrocarbon ratio versus hydrocarbon-to-organic-carbon ratio.

Finally, after determining the time of gas generation, regional paleomigration pathways can be mapped by utilizing present-day geothermal gradients and burial history, combined with data from stratigraphic and structural studies.

3. <u>Reservoir properties</u>--Any study of hydrocarbon accumulations and resource volumes must identify the critical reservoir characteristics and their controlling factors. Reservoir characteristics are particularly critical in the low-permeability range.

<u>Objectives</u>:

a. Describe the petrography of the various tight gas reservoirs including matrix cement, pore throats, diagenesis, and paragenesis.
b. Using available geophysical porosity logs, adjusted to core data, prepare isopach maps of gas-bearing reservoirs.
c. Determine the effects of depth and temperature on porosity-permeability characteristics.
d. Evaluate the effects of the above elements and depositional environments on reservoir quality and on the migration and entrapment of natural gas.

e. Compile regional formation-pressure and fluid data for key reservoir beds in each basin.
f. Determine the limiting reservoir characteristics of tight gas sandstones for each study area.

Methods:

Borehole logs will be analyzed. Core analyses will provide partial information on porosity, water saturation, capillary pressure, permeability (air), gas-water relative permeability, and grain density. Core and outcrop samples are being examined microscopically using thin sections, impregnated with colored epoxy in a vacuum oven, to determine rock composition and to make pore and pore-throat studies. Pore-throat geometry and size are being studied by scanning electron microscope (SEM). Data from this study will be combined with other information, such as clay mineralogy, environments of deposition, and occurrence of gas. This work will lead to the identification of the limiting reservoir qualities of tight gas reservoirs and to the delineation of areas where the tight sandstones have maximum gas potential. The complexity of the log analysis problems requires the geological program to rely heavily on ERDA-supported logging research and service companies for assistance.

4. Clay mineralogy studies--Little is known about the clay mineralogy of clastic reservoirs and associated facies in the Rocky Mountain region. Preliminary data indicate that clays have a strong influence on reservoir permeability, susceptibility to formation damage, and approaches to recovery problems.

Objectives:

a. Determine the types, exchangeable cations, swelling characteristics, and amounts of clay minerals present in tight gas sandstones and associated rocks.
b. Determine the origin of the clays.
c. Determine relationship among specific types of clay and occurrence of natural gas.
d. Determine the character of the clays in the pore throats of tight reservoirs using SEM and electron-probe techniques. These studies will provide valuable information for analyzing permeability data, interpreting borehole logs, and designing stimulation methods that will decrease effects of formation damage during drilling and testing.

Methods:

Core samples, supplemented by outcrop samples, are being processed in the USGS core library and analyzed by X-ray diffraction and fluorescence methods to determine the percentage and types of clay minerals. The distribution of clays on the pore walls and in pore throats will be observed by SEM and electron probe. Wet lab techniques will determine exchangeable cations and swelling characteristics.

Data from these analyses will be presented on maps and cross sections delineating the locations of specific clay-mineral types. Local and regional variations in occurrence and type of clay will be compared with such factors as depositional environments, gas production, and lithologic character. Coordination will be necessary with ERDA and ERDA contractors to provide input into enhanced recovery research.

5. Coring program--Much of the basic data for the stratigraphic, geochemical, reservoir, and clay-mineralogy studies is being obtained from subsurface cores. Outcrop samples can be used for some studies, but subsurface core samples are needed because they more accurately reflect the true reservoir conditions. Cores are not available in many parts of the project areas either because they were not taken due to economic restrictions of the drilling programs or because available cores were not preserved. Cutting of cores should be done under the direction of ERDA and can be coordinated under contract with operators actively drilling in the study areas as a part of ERDA's massive hydraulic fracturing (MHF) and other projects. The USGS has the personnel and facilities necessary for processing and storing cores.

6. Data acquisition and processing--Some basic regional geological and engineering data have been extracted by computer from the Petroleum Information Well History Control System (WHCS), a computer file which contains data on more than 120,000 wells in the Rocky Mountain region. However, because only limited geological studies have been performed on the tight gas sandstones, the USGS is establishing a data base for all information collected in field, subsurface, and laboratory studies as part of the program. This information will be in a format compatible with the WHCS. The WHCS system has been purchased by the USGS, and Petroleum Information is under contract to perform required processing.

   Maps and data being generated from this system are as follows:

   a. Well-penetration maps for objective reservoir intervals.
   b. Regional structure maps.
   c. Map plots and printouts of cores and drillstem tests (DST's).
   d. Map plots of all reported oil and gas shows and production.
   e. Plots of DST's for which initial shut-in pressures (ISIP) are at least two times final shut-in pressures (FSIP).

f. Regional hydrodynamic maps from hydrostatic levels that are machine-computed from DST's for which ISIP is less than two times the FSIP.
g. Preliminary bottomhole-pressure maps from shut-in pressures using only DST's that had preflows to remove supercharge (using DST's described in "f" above).
h. Map plots of pressure gradients from highest of ISIP or FSIP.

7. Borehole gravity surveys--Where feasible, borehole gravity surveys will be used on an experimental basis for the assessment of the natural gas potential of tested and untested tight gas reservoirs. This well-logging technique provides evaluation of formation density, which is the integrated effect of rock and fluid density that extends tens to hundreds of feet outward from the borehole.

Objectives: Borehole gravity surveys can be selectively made to accomplish the following:

a. Evaluate fracture porosity of tight gas sandstones both before and after stimulation experiments.
b. Determine the areal extent of lenticular reservoirs using the density contrast between shale (2.0-2.4 g/cc) and sandstone (2.65-2.7 g/cc).
c. Provide accurate average-density data for thick, tight sandstones.
d. Construct acoustic impedance logs, if necessary, to be used in conjunction with well-velocity surveys for refinement of seismic interpretations.
e. Refine log interpretations and core analyses.

Methods:

Several surveys will be coordinated with ERDA drilling and coring programs. These surveys will be selectively chosen over the life of the program. Bulk density, matrix porosity, grain density, and fluid saturation should be furnished before the interpretation of the surveys can be made. This study will require close coordination with present and future ERDA coring, stimulation, well-testing, and completion programs.

8. Resource appraisal--The USGS Resource Appraisal Group (RAG) will analyze available data during the study period to provide geologically based estimates of gas-in-place. These estimates will require RAG to work closely with each study group and utilize all available data. RAG will then work closely with ERDA to generate recoverable-gas resource estimates based on latest advancements in recovery technology.

The basic stratigraphic and petrophysical studies are being done within the USGS, because this work provides the basic geologic framework for the entire program. In addition, the USGS has in-house expertise in these areas, and the program work is being integrated with ongoing studies. Geochemical analyses and some core-analyses work are being done through outside contracts because USGS laboratories are not equipped for batch processing. Final integration and interpretation of data will be made by USGS personnel. Investigations by the USGS will be continuously coordinated with past and present studies of other groups, including the Plowshare and the MHF projects, to avoid duplication of effort, to minimize expenses, and to gain maximum benefit from the mutual exchange of ideas.

Piceance and Uinta Basins

Gas accumulations in low-permeability sandstone reservoirs of Late Cretaceous, Paleocene, and Eocene age in the Piceance and Uinta Basins occur in both marine and nonmarine depositional environments. These basins are shown in Figure 1. Initial inspection of the productive marine units indicates that many of the reservoirs occur in offshore and barrier-bar settings where sandstones were deposited adjacent to swamp, lagoonal, or carbonaceous-marine beds. These rocks were buried to sufficient depths to serve both as stratigraphic traps for, and a source of, gas or were located on a regional migration path for hydrocarbons. However, many of these continuous sandstone units may have been adversely affected by early calcite and silica cementation and by the formation of clay minerals in pore throats, so that the reservoir quality of the units is significantly reduced or destroyed (J. K. Pitman, oral commun., 1977). In the area of study, the marine units are easily correlatable; however, where the rocks grade regionally to the west into nonmarine beds, the sandstones become more discontinuous and consequently more difficult to correlate. Examples of relatively continuous marine reservoirs are present in parts of the Castlegate, Rim Rock (of Walton, 1944), and Sego Sandstone, Corcoran and Cozzette Members (of Young, 1955) of the Price River Formation, Trout Creek Sandstone Member of the Iles Formation, and Rollins Sandstone Member of the Mount Garfield Formation, all units of the Upper Cretaceous Mesaverde Group.[1,2,3]

Gas is also trapped in nonmarine sequences in alluvial sandstone reservoirs. Individual and composite channel-form sandstones account for as much as 90 percent of the potential reservoir units in the alluvial section. Although many correlatable sandstone units developed at approximately the same time over a large area, the resultant reservoirs are commonly small because claystone and siltstone beds intertongue both laterally and vertically within a short distance. Ubiquitous large-scale, low-angle cross strata are commonly separated by relatively nonpermeable claystone beds. This factor would seem to minimize the potential for single large pools of gas, except where the reservoir rocks are on the crest of a structure. Individual reservoir trap and source beds are common, however, and cumulatively may contain much gas. Examples of nonmarine units which contain such discontinuous reservoirs, include the Williams Fork, Iles, Hunter Canyon, Mount Garfield, Blackhawk, and Price River Formations and including in some areas both Neslen and

Farrer Formations all of the Mesaverde Group, and parts of the younger North Horn Formation.

All Tertiary rocks in the area of study are believed to be of nonmarine origin.[4,5] The gas produced from nonmarine rocks of Tertiary age comes from channel sandstones which were deposited adjacent to swamp or lacustrine environments.[6] It is noteworthy that much of the gas presently produced in the area is from reservoirs in nonmarine Paleocene and Eocene rocks. This production is commercial to marginally commercial (near tight) and is from stratigraphic traps in the Wasatch (or part of the Fort Union Formation of some authors), North Horn, Ohio Creek, and Green River Formations. Fouch stated that the traps in these swamp and lacustrine deposits are a function of (1) change in clay content within a single channel; (2) change from one genetic sandstone type to another, such as a channel to an associated overbank sandstone; (3) change in cementation; and (4) regional facies changes.[7] Correlation is difficult in the nonmarine rock sequences, and new dating of the rocks indicates that some of the gas that has been believed to have been produced from Paleocene units is probably from reservoirs of Cretaceous age which unconformably underlie the Tertiary rocks (R. C. Johnson, oral commun., 1977). Correct correlation is critical to an estimation of reserves for a unit on a regional basis, and paleontologic data are being obtained to correctly identify and relate the rocks.

To date, the USGS work in the Uinta-Piceance study area has centered on establishing major reference sections of the objective rock units. In addition to outcrop descriptions of genetic units, specimens are collected for paleontologic, mineralogic, petrographic, and geochemical analysis. Several cores of reservoir rocks from producing fields and core from near outcrop sections have been described in detail and should be excellent material for studies of reservoir- and source-rock units. A stratigraphic section of some Upper Cretaceous and lower Tertiary rocks that extends from outcrops along the southwest part of the Uinta Basin to the subsurface of the Duchesne and Altamont oil and gas fields has been completed and approved for publication by the U.S. Geological Survey. These data will soon be released as an open-file report.[8] The cross section will relate rock groups and types, engineering data, productive facies, and correlations.

Greater Green River Basin

Figure 1 shows the location of the Greater Green River Basin study area. Sandstone reservoirs having the best potential for gas accumulation in tight reservoirs occur in nonmarine deposits of the Upper Cretaceous Mesaverde Group and Lance Formation and Tertiary Paleocene Fort Union and Eocene Wasatch Formations. Some potential for tight gas reservoirs exists in marginal-marine rocks in the Mesaverde Group and Fox Hills Sandstone, and marine sandstone and siltstone above and below the Mesaverde. In addition, rocks of early Late Cretaceous age in the Frontier Formation have some potential for gas in tight sandstone but are not currently an objective for study because the reservoirs are thin and of limited areal extent. In general, most marine sandstone has better reservoir quality and would not be classified as tight.

Some presently commercial production is obtained from Frontier, Mesaverde, Fort Union, and Wasatch units in the basin, so it is obvious that all gradations exist from good permeable reservoirs to tight rocks. As of January 1, 1973, the Wyoming portion of the basin contains 60 percent of Wyoming's gas production and reserves and, in spite of the numerous wells drilled, the basin's rock volume is only 2.7 percent explored.[9] Ninety-three percent of the presently commercial gas in this portion of Wyoming has been found in Cretaceous and Tertiary rocks. About 44 percent of the Tertiary and Cretaceous gas has been found in Mesaverde and younger reservoirs.[9]

Generally the Upper Cretaceous strata thicken from east to west and become more nonmarine (continental) to the west. Drilling depths to the base of the Mesaverde vary from less than 2,000 feet near uplifts to more than 19,000 feet in the northwest part of the basin. The present structural configuration of the basin is due to tectonism in the Upper Cretaceous, Paleocene, and Eocene.

Present reconnaissance work has concentrated on compilation of published and unpublished surface and subsurface data. Networks of regional electric-log stratigraphic sections have been constructed and are being correlated using lithologic well logs and surface data. Correlations in the thick continental sequences are very difficult, and micropaleontologic work is underway to refine age relationships.

Some processing of Petroleum Information's Well History Control System (WHCS) data has been completed in work-map form. Printouts of WHCS-core, hydrocarbon-show, drillstem-test, and pressure data have been generated. The preliminary pressure-gradient data indicate several areas having above-normal reservoir pressure. Temperature, well-penetration, and regional-structure maps have been requested for processing. Core samples have been collected for petrographic, geochemical, and paleontologic processing.

Northern Great Plains

The northern Great Plains study area, as shown in Figure 1, is situated in eastern Montana, western North and South Dakota, and northeastern Wyoming. It comprises a large portion of the Williston Basin. This area has not been included in previous natural gas resource reports due to lack of engineering and geologic data. Current investigations in the study area and the recent exploration and evaluation of similar facies in western Canada indicate that major gas resources are entrapped in low-permeability reservoirs of Cretaceous age at depths of less than 4,000 feet.

These shallow accumulations of gas, which consist predominantly of methane, are the product of the immature stage of hydrocarbon generation.[10]

The methane is generated by the breakdown of organic matter by anerobic bacteria at shallow depths in accumulating sediments and is called biogenic gas. The accumulation of biogenic gas is favored by the rapid deposition of organic-rich sediments and by the presence of a reservoir or seal either during peak generation or later, when uplift and erosion cause exsolution of the gases from formation waters. The deposition of discontinuous and/or low-permeability silts, sands, and marls enclosed by thick sequences of mud during Cretaceous time in the northern Great Plains, provided excellent conditions for the accumulation of biogenic gas.

Biogenic gas is characterized by the enrichment of the light isotope C^{12} in methane (δC^{13}-58 $^{o}/oo$) relative to the PDB standard, and by large amounts of methane (C_1) relative to ethane and heavier hydrocarbons (C_1/C_5>0.98).[1] Gases from the Bowdoin field in north-central Montana[1] have δC^{13} values ranging from -68.6 $^{o}/oo$ to -72.3 $^{o}/oo$, with hydrocarbon compositions consisting of greater than 99 percent methane. These gases are of biogenic origin and are considered typical of the northern Great Plains province.

Prospective low-permeability gas reservoirs in the northern Great Plains range in age from late Early Cretaceous to Late Cretaceous. The objective reservoirs are thin, discontinuous siltstones and sandstones enveloped by thick sequences of shales. These shales may serve as both source rocks and potential reservoirs where naturally fractured. More persistent marls in the Upper Cretaceous Greenhorn, Carlile, and Niobrara Formations having high porosity but low permeability, are probable targets, particularly in the eastern part of the study area. All of these tight reservoirs were deposited in a low-energy shelf environment along the north-south trending Western Interior seaway. Investigations by G. W. Shurr (USGS) in part of the study area show that paleomovement along lineaments, as mapped from satellite images, had primary control on the distribution and development of facies, particularly in the shelf setting.[11] In addition, fracturing and faulting along these lineaments will probably lead to enhanced gas recovery. Future studies will document the influence of these lineaments over the entire study area on facies distribution, fracturing, and ultimate gas recovery.

The regional stratigraphic framework of the potential gas-bearing sequence in the northern Great Plains has been established by Rice.[12,13,14] Regional cross sections illustrate that the correlation and occurrence of mappable units of predominantly marine shale are predictable over a large area. However, the reservoir characteristics and thus the resource potential may change drastically over short distances. Future studies will attempt to identify what parameters are best for mapping gas potential.

Figure 2 is a correlation chart for north-central and eastern Montana and southeastern Alberta, two areas which have had recent production from relatively low permeability reservoirs. The most actively explored area in north-central Montana is the Bowdoin gas field which covers an area of 600 square miles. Production comes from the upper part of the Belle Fourche, the Phillips sandstone of subsurface usage within the Greenhorn

Formation, and the Bowdoin sandstone of subsurface usage within the Carlile Formation, at depths ranging from 400 to 1,800 feet. Wells are typically low volume and are commercial only after fracing, but they are predicted to have a long life. The Canadian equivalent of the Greenhorn Formation, the second white specks zone, is also productive in Alberta. However, the correlatives of the main producing zones in Alberta, the Medicine Hat Sandstone and Milk River Formation, have not been adequately evaluated in Montana. Likewise, the equivalent of the productive zone in the Carlile, the Bowdoin, has not been adequately tested in Alberta. Our investigations indicate that all of the section between the Mowry and the Bearpaw Shales (Fig. 2) has similar log characteristics and should contain potential tight gas zones in the study area. The Eagle Sandstone and Judith River Formation are potential tight gas units only eastward of the porous and permeable shoreline sandstones.

The best documented gas production from tight reservoirs in the northern Great Plains study area occurs in western Canada. Available references have been compiled.[15] However, as is true in the United States, most of the research has been on stimulation and recovery technology and not on the geologic framework. The Suffield Evaluation Committee, appointed by the Province of Alberta, evaluated an area of 1,000 square miles in southeastern Alberta which had a 77-well program completed in 1974. Seventy-six of the wells were gas wells. The Committee assigned an in-place gas reserve figure of 3.7 Trillion-cubic-feet (Tcf) to the area. This gas-bearing facies continues into Montana and is present over an area of at least 35,000 square miles in the United States' portion of the northern Great Plains. Using the Suffield Block reserve data, the United States' portion should contain 130 Tcf of gas in-place and recoverable gas resources of approximately 90 Tcf.

CONCLUSIONS

The USGS has initiated geological studies aimed at characterizing gas resources in the western tight gas reservoirs. The initial work involves a large amount of compilation of surface and subsurface data. Approximately 20 preliminary, regional stratigraphic sections, utilizing electric logs and surface sections, have been constructed in order to properly correlate equivalent gas-bearing intervals. Many of the rocks being investigated are nonmarine deposits which have been extremely difficult to correlate in the past. Computer processing of WHCS data is in progress and will be refined for publication. Numerous rock thin sections have been prepared and are being analyzed. Petrographic studies of reservoirs to date have shown that the distribution of clays in pore throats greatly reduces reservoir permeability. Whole-rock, clay-mineral analyses show that a variety of clays are commonly present in a reservoir. However, when the SEM is used in conjunction with X-ray fluorescence studies, it can be shown that only one type of clay may be critical to permeability and stimulation problems. Lack of recognition of the distribution of clays in reservoir beds may account for anomalous results of some production tests.

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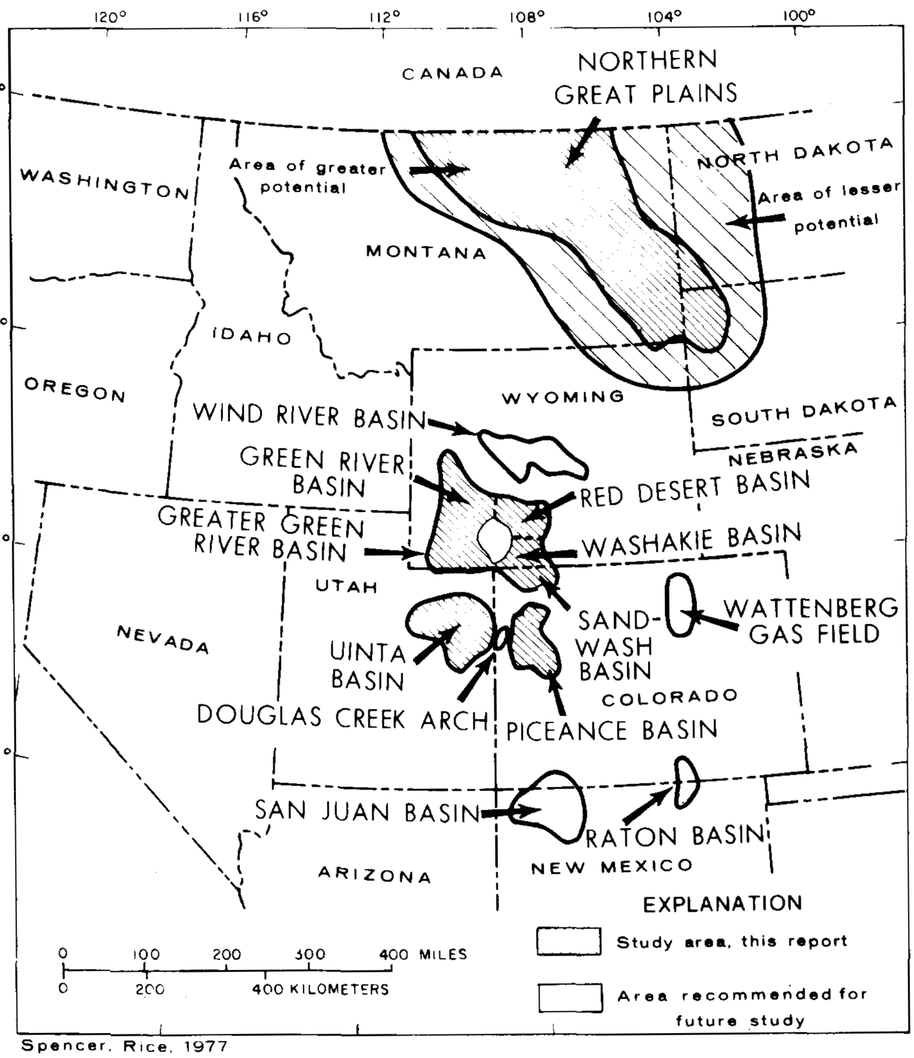

Figure 1.--Index map of Rocky Mountain areas with potential for major resources of gas in low-permeability reservoirs.

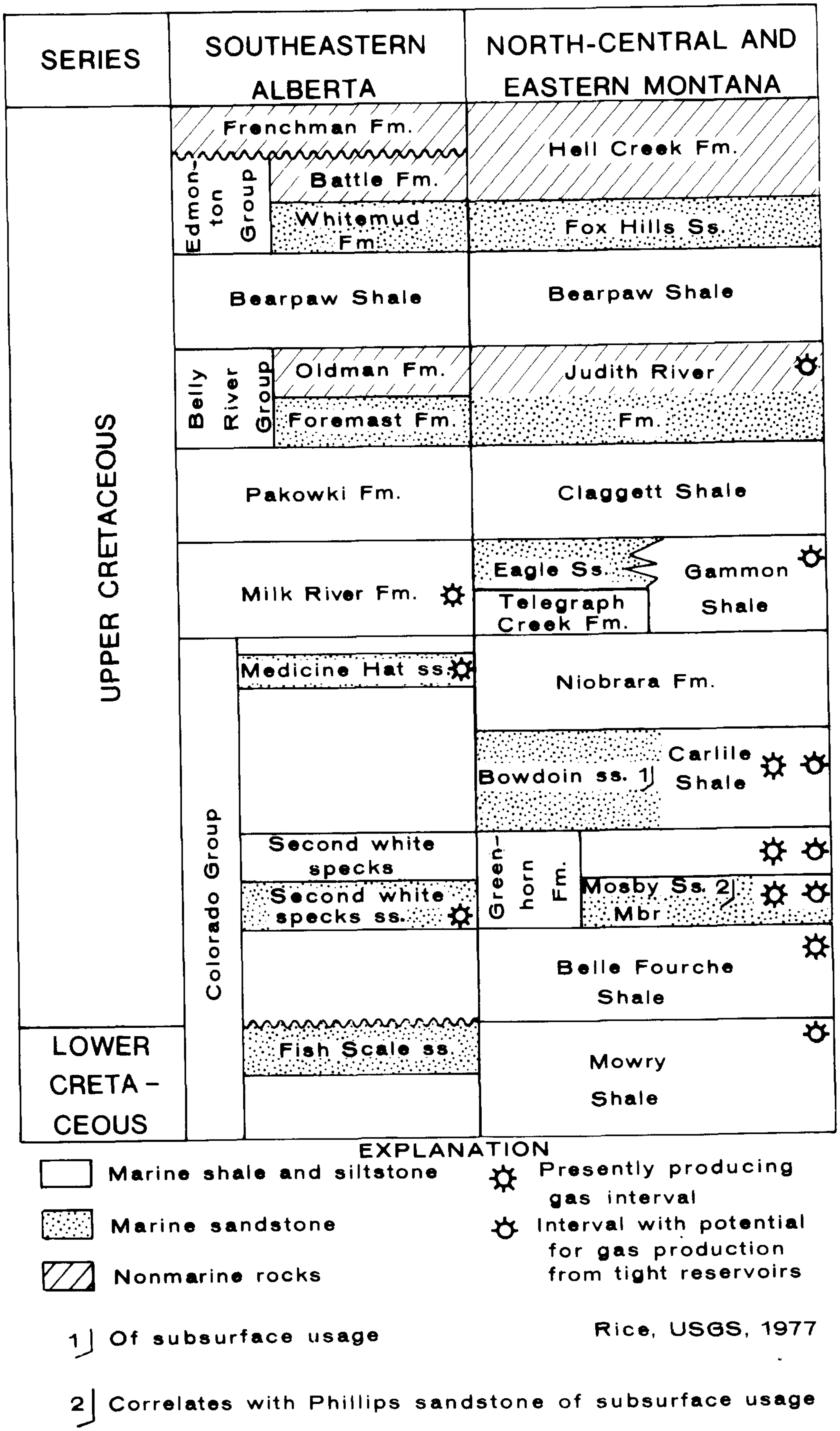

Figure 2.--Stratigraphic chart showing correlation of selected Upper and Lower Cretaceous rocks currently producing natural gas, and intervals with potential for gas production from tight reservoirs in the northern Great Plains.

MASSIVE HYDRAULIC FRACTURING GAS STIMULATION PROJECT

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ABSTRACT

The Rio Blanco Massive Hydraulic Fracturing Project was fielded in 1974 as a joint Industry/ERDA demonstration to test the relative formations that were stimulated by the Rio Blanco Nuclear fracturing experiment.(1) The project is essentially a companion effort to and a continuation of the preceding nuclear stimulation project, which took place in May, 1973.

The Rio Blanco projects are located in the northern part of the Piceance Basin of Northwestern Colorado (Figure 1), one of a number of basins in the Western United States that have substantial quantities of natural gas locked in tight sand-shale reservoirs. These reservoir rocks are of such heterogeniety and have such low permeability, however, that conventional methods of stimulation have been ineffective and uneconomical.

GEOLOGIC SETTING

The Piceance Basin is one of two large structural downwarps that, with their adjacent structural highs, dominate the geologic structure of Northwest Colorado. Total structural relief in the Northern Piceance Basin (Figure 2) is 14,000 ft; more than 20,000 ft of sedimentary rocks are found here, of which about half can be classed as tight gas sands and shales. Commercial gas production is found mainly in the basal Green River and a lesser amount in the Wasatch, both Eocene. A number of marginal and sub-commercial gas wells tap the Fort Union (Paleocene) and Mesaverde (Upper Cretaceous) formations. Lower Mesaverde and Mancos production is found in the southernmost part of the Piceance and older formations are productive on the adjacent Douglas Creek Arch.

The gas bearing formations of interest in the project area (Figure 3), the Fort Union and Mesa Verde, range up to 4,000 ft in combined thickness and are estimated to contain as much as 74 billion cubic ft of gas in place per square mile. The multiple sandstone reservoirs comprise lenticular shaly and silty sands, primarily of fluvial origin, and of relatively limited lateral extent, occuring intermittently throughout a thick section of shale and siltstone, as shown diagrammatically in Figure 3.

RESERVOIR CHARACTERISTICS

In general, these tight gas formations comprise predominantly shales and siltstones with a few cleaner sandstones; the sandstones are frequently shaly and silty and contain water-sensitive clays. Net pay is difficult to differentiate

(1) Prepared for ERDA under Contract No. E(26-1)-623

because of the gradational nature of the strata. Technical information is scanty; many times, the tight gas sands have been drilled through and logged, recognized as non-commercial, and eliminated from further consideration. As a result very little detailed geological information has been made available to more accurately assess the potential of these formations.

In the project area, the Fort Union Formation is about 870 ft thick. The partial Saraband log (Figure 4), shows graphically the variable nature of the potential reservoir sands, which have substantial clay and silt content and grade into the interlayered shales. In the two zones of interest, 5850 - 5872 ft and 5925 - 6033 ft, core and log analyses indicate a median porosity of about 8%, with actual porosities ranging from 2 to 11%, water saturation about 50%, and permeability to gas, as measured from dried cores, from 10 microdarcies to 2 millidarcies.

The Mesaverde Formation (Figure 5) is about 1690 ft thick to the lowest sand penetrated, the interval from 6482 - 6800 ft being considered the Upper Mesaverde and 6800 - 8172 ft the lower Mesaverde. Figures 5 and 6 depict two intervals within the Mesaverde that were considered for fracturing. These sands have a range of porosity of 3 to 9% and average about 7%. Water saturation is 60% and permeability to gas 8 to 60 microdarcies.

The reservoir characteristics of these tight sands are poor at best, and as depicted by the logs and verified by minerologic and petrographic studies have a variable, but usually substantial, clay and silt content. The gradational contacts between the sands and the shales provide little impedance to vertical extension of fractures. In conventional stimulation practice the physical characteristics and strengths of the two rocks types, shale and sand, are usually sufficiently different to control fracture extension. This however, does not appear to be the case in the Fort Union and Mesaverde formations in the Piceance Basin, because of the shaly-silty nature of the sand and the gradation between rock types. There is also some evidence that the shale and silts are more brittle than the sands, have a higher incidence of natural fractures, and are, therefore, more susceptible to fracturing. As a result, the design and execution of a fracture treatment must be closely controlled to attain the desired results.

Permeabilities in the low microdarcies range, such as are found in the Fort Union and Mesaverde, are strongly and adversely affected by liquid saturations and by compaction. Published results of work on similar tight sands have been expanded by similar studies of Rio Blanco cores. In Figure 7A dried core with an air permeability of about 50 microdarcies at surface conditions, shows an effective permeability of 5 to 10 microdarcies at confining pressures between 2000 and 3000 psi. In Figure 7B, the compacted samples show no permeability to gas at water saturations between 60 and 80%.

MHF WELL NO. 3

The Rio Blanco Unit MHF Well No. 3 is located in Section 11, T3S, R98W, in Rio Blanco County, Colorado, near the center of the Piceance Basin. It is on lands dedicated to the Rio Blanco Gas Unit and is one mile northeast of the Rio Blanco Unit E-01, the nuclear emplacement well, (see Figure 3). The MHF 3 well was spudded on May 21, 1974 and completed on September 13, 1974. A total of four strings of casing were set. The 10-3/4 in. OD intermediate casing was set at 5603 ft in the top of the Fort Union Formation, casing off all the overlying Wasatch and Green River; 7 in. production casing was set at 8162 ft in the lower Mesaverde.

A total of ten cores were cut between 5925 - 7085 ft. Five drill stem tests were attempted, but only one was considered successful; one test failed and on three tests packers leaked during shut in, a measure of the competency of the strata. Air and stable foam were used to drill the hole from 5063 - 6240 ft. Measurements of gas flow from the open hole section through this interval aided in determining the reservoir quality of the sands; these rates ranged from 10 MCF/D to a maximum of 89 MCF/D. During the drilling of the well and after its completion, the hole was extensively logged.

FRACTURE TREATMENTS

The well has been fractured a total of four times: twice in the lower Mesaverde and twice in the Fort Union. A fifth zone, in the Upper Mesaverde, was extensively tested but abandoned as being of insufficient quality for fracturing. Our self-imposed limits for fracturing required a minimum of 0.2 md-ft productive capacity or 5 microdarcies permeability in the zone.

Table 1 shows the characteristics and results of each of the fracturing treatments. Preparatory operations have been similar for each; the well is first perforated dry and the zone allowed to produce naturally for a short period. The perforated interval is then broken down with 5,000 to 10,000 gals of 2% KCl brine using ball sealers to assure breakdown of each perforation. This initial treatment is cleaned up and the zone flowed for 5 to 10 days, after which the well is shut in for two weeks to one months for pressure build up and analysis. This procedure permits the determination of the natural productive capacity, kh, upon which determinations of fracture capacity, and to some extent, geometry are based.

After completion of pre-frac analyses, the zone is given a massive hydraulic fracturing treatment. This is followed by a clean up and flow period of about two months. A packer is set on tubing above the zone during the initial clean up in order to reduce after flow volume. After gas flow has stabilized and about 55 to 60% of the frac load recovered, the well is again shut in for buildup, usually for two months.

The results of our fracturing treatments are now being analyzed. The experiment has essentially been completed, lacking only a flow test of the combined zones and final analysis. A complete report will be published in the future.

CONCLUSIONS

The work in the Rio Blanco Unit MHF 3 was established as an experiment to test the usefulness and economics of massive hydraulic fracturing in the Fort

Union and Mesaverde sands of the Piceance Basin and to obtain a comparison of the technique with nuclear stimulation. Recent large fracturing treatments in other selected areas have been very successful, but the success ratio in areas of previously non-commercial reservoirs such as the Piceance, Uinta, and Green River Basins has been poor.

The participants in the project have conducted extensive studies to define optimum fracturing design and technologies, fluid formation compatibility, possible remedial measures, and the variables associated with stimulation in these difficult areas.

In the four treatments, none appear to have fractured laterally as designed. In the Fort Union and Mesaverde each well must produce from numerous lenses of sand, the lateral extent of which appears to be limited. This lenticularity substantially reduces the overall average permeability, formation productive thickness, and effective drainage area available to the fracture. Calculated propped fracture lengths are quite short. In our analyses we have surmised very low fracture conductivities, 1/5 to 1/20 of design. Current analytical techniques assume infinite fracture conductivity. One MHF analytical effort has been able to obtain good performance matches in modelling continuous sands, but have had to reduce net sand quantity by 75% to match the production performance of lenticular sands such as those in the Mesaverde. We postulate several possibilities: We are fracturing out of zone with vertical propagation of the fractures instead of horizontal as designed, the sand lenses have substantially smaller dimensions than design fracture lengths, and conventional logging and analytical techniques available to us are not sufficiently discriminatory in these environments to differentiate net pay from non-productive formation. We think all of these possibilities are operative in the tight gas sands.

We need to develop techniques that will define, if not control, the extent, shape, and orientation of fractures. This is primarily a function of mechanical rock properties and existing rock stresses; our knowledge in these areas is deficient. Geologic analyses are required to define areas of maximum sand content, the probable extent and distribution of lenticular sands, and the stratigraphic and structural features that affect or control sand distribution and fracture orientation.

Fracturing fluid technology is quite advanced, but additional work is required to define viscosity changes with temperature, especially as it relates to fracture extension, closure, and proppant transport. In the first two of our treatments we used a polyemulsion suspending type fluid, and the last two, a single phase equilbrium bank fluid. Fluid returns after fracturing have been comparable for the two types of fluid, except for one abberration: In frac No. 1 we had a preferential return of the lighter napthenic-oil over the heavier diesel oil from the frac oil mix. Sand recovery after frac has been nominal, less than one percent of frac volume, except in the third frac which sanded out.

The reservoir rock properties of commercially productive reservoirs are substantially better than in these tight gas sands we are now evaluating. They are less affected by compaction and relatively slight changes in saturations.

The usual industry techniques for determining porosities, saturations, and permeabilities can be relied upon to produce acceptable if not precise answers in those formations. However, as the reservoir rock properties become poorer, the standard industry practices for determination of these variables becomes suspect. The need for new and better techniques for evaluation of the parameters is critical. Determinations of bottom hole temperatures, pressure and porosity appear to give reasonable results. However, accurately defining water, oil and gas saturations, permeability, and differentiating net pay, particularly under in situ conditions, are major areas where the present technology is lacking. Techniques must be refined to define these values in tight, shaly-silty sands, and their relation to productivity.

With the current state of technology, our best determinative technique is still long term testing. Accurate predictions of production depend upon reliable pressure testing, and in tight sands of the Western Rocky Mountains, this currently requires long term flow, followed by long term build up; each phase on the order of two to four months.

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TABLE 1
FRACTURING TREATMENTS—MHF 3

FRAC. NO.	1	2	—	3	4
ZONE	8048-8078 ft. L. Mesa Verde Single Sand	7760-7864 ft. L. Mesa Verde Multiple Sands	6736-6806 ft. U. Mesa Verde Multiple Sands	5925-6016 ft. Fort Union Multiple Sands	5851-5869 ft. Fort Union Single Sands
PERFS	25	40	12	20	36
BHT	242°F	225°F	210°F	201°F	197°F
NAT. FLOW	1 MCF/D	5-10 MCF/D	5-10 MCF/D	42.5 MCF/D	56 MCF/D
AFTER B.D.	60 MCF/D	57.3 MCF/C	27.7 MCF/D	——	——
BHP	3450 psi	——	2828 psi	——	2092 psi
MHF	Poly E, Sus- pended bed. 117,500 gal. 400,000 lbs Naptha-type Diesel mix refined oil, kcl brine	Poly E, Sus- pended bed. 285,000 gal 880,000 lbs Naptha-type Refined oil, kcl brine	No Frac	Logel kcl brine, Equilibrium Bank. 344,000 gal 809,000 lbs	Logel kcl brine, Equilibrium Bank. 228,000 gal 448,000 lbs
FRAC RATE	16-22 BPM	45 BPM		20-25 BPM	15-25 BPM
TREAT PRESS.	4880-5800 psi	3800-5300 psi		800-5500 psi	1200-5000 psi
ISIP	4500 psi	3170 psi		Sand Out	4450 psi
FLUID REC.	59%	59.5%		65.5%	56.4%
GAS RATE	60.7 MCF/D	137 MCF/D		160 MCF/D	69 MCF/D
PROD. CAP.	0.15 md-ft	.3 md-ft	0.017 md-ft.	.3-.5 md-ft	.3 md-ft
CALCULATED FRAC LENGTH (Type Curve Match)	110' - 170'	150'		100'	20' - 30'
REMARKS	Sand Return Negligible	Plugged by fm. solids (Fe minerals.) Rec. 7000 lbs sand.	Zone Squeezed	Zone Squeezed Sanded out on frac- rec. 37000 lbs sand.	Rec. 6200 lbs sand.

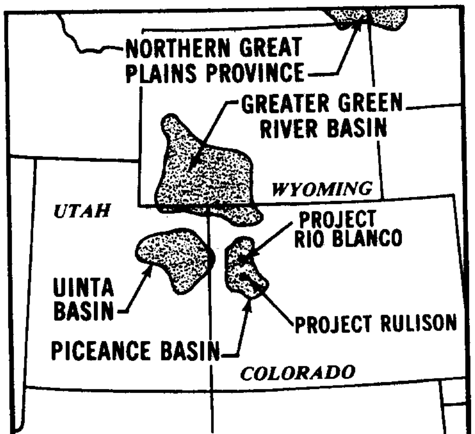


FIGURE 1.
TIGHT GAS RESERVOIRS
IN THE ROCKY MOUNTAINS

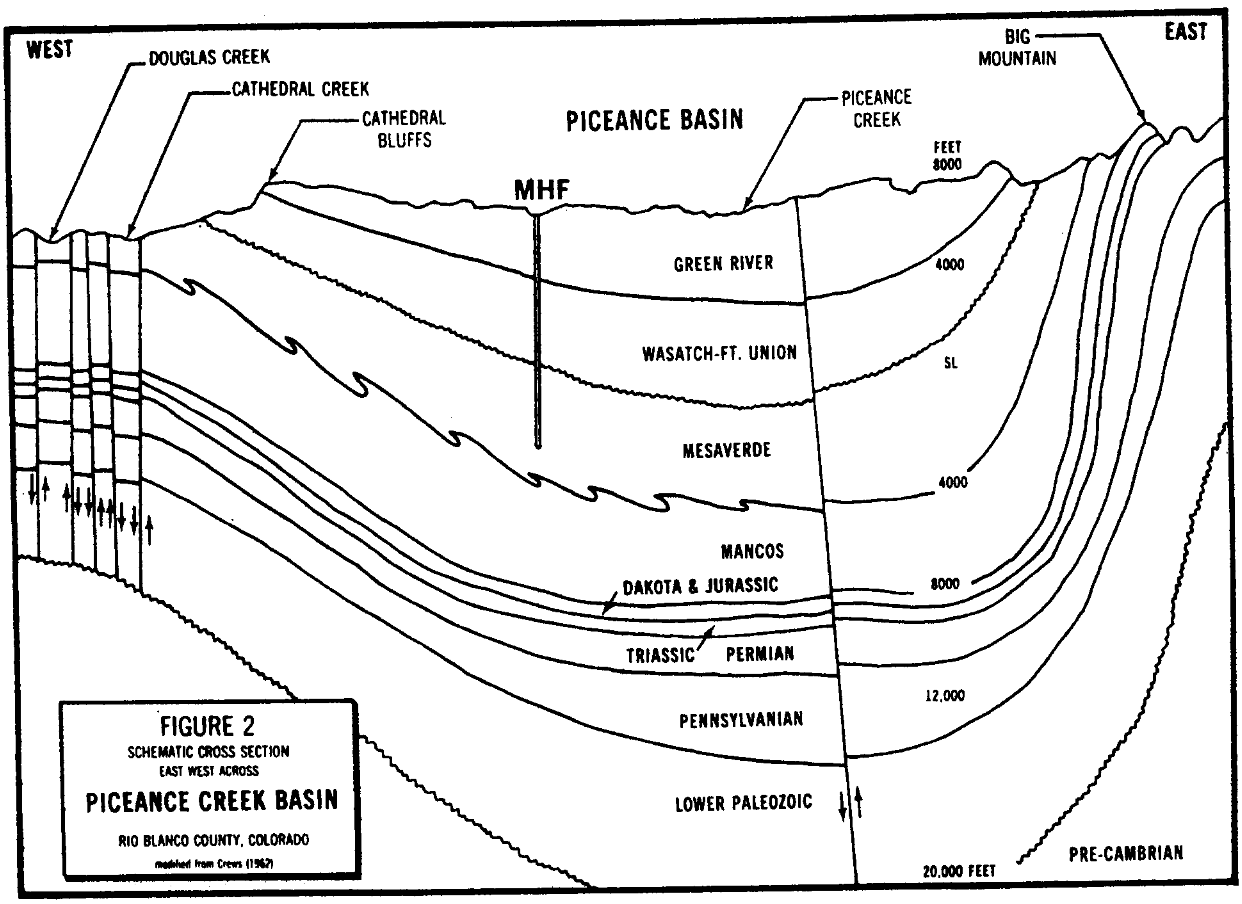


FIGURE 2
SCHEMATIC CROSS SECTION
EAST WEST ACROSS
PICEANCE CREEK BASIN
RIO BLANCO COUNTY, COLORADO
modified from Crews (1962)

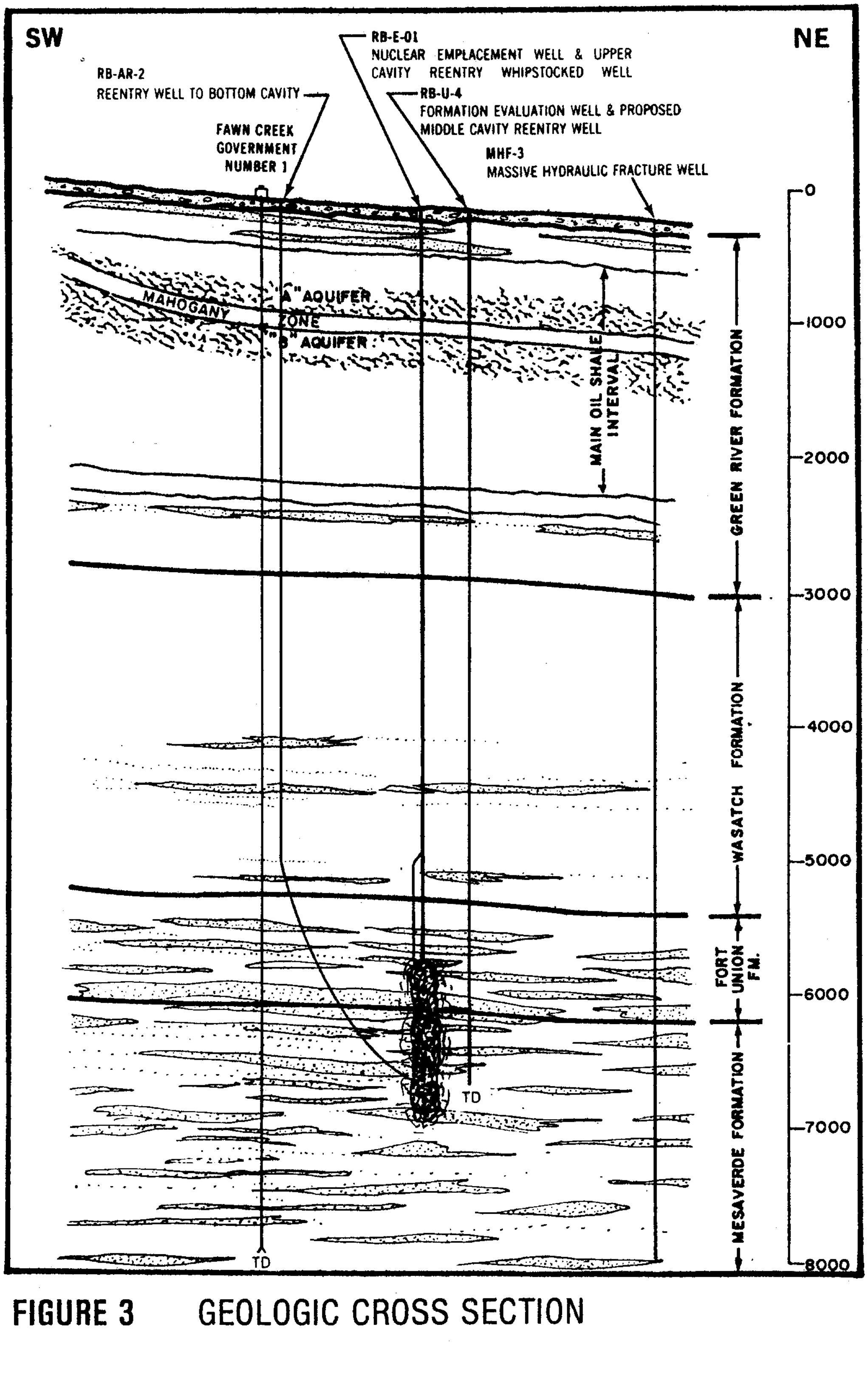


FIGURE 3 GEOLOGIC CROSS SECTION

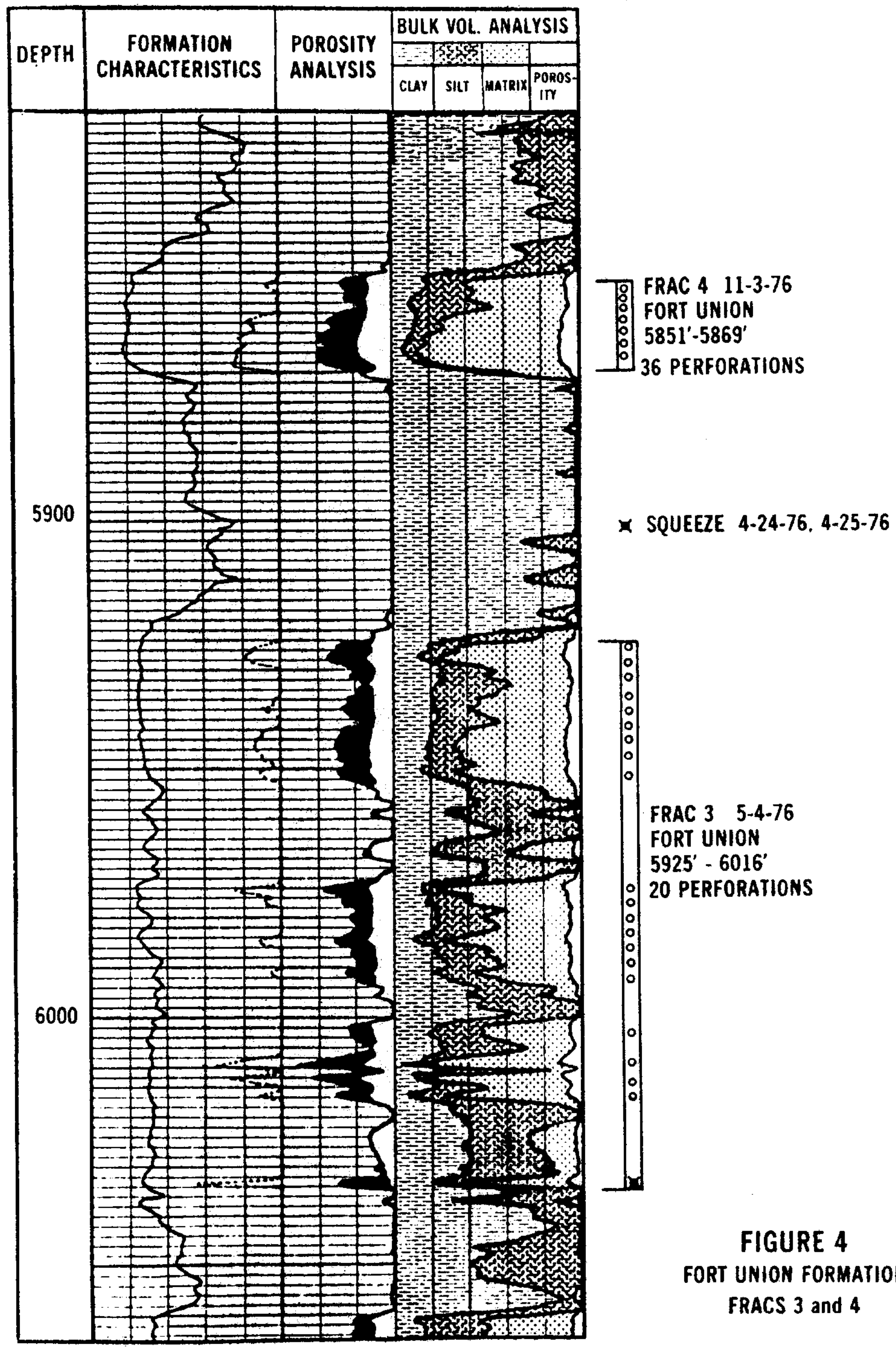


FIGURE 4
FORT UNION FORMATION
FRACS 3 and 4

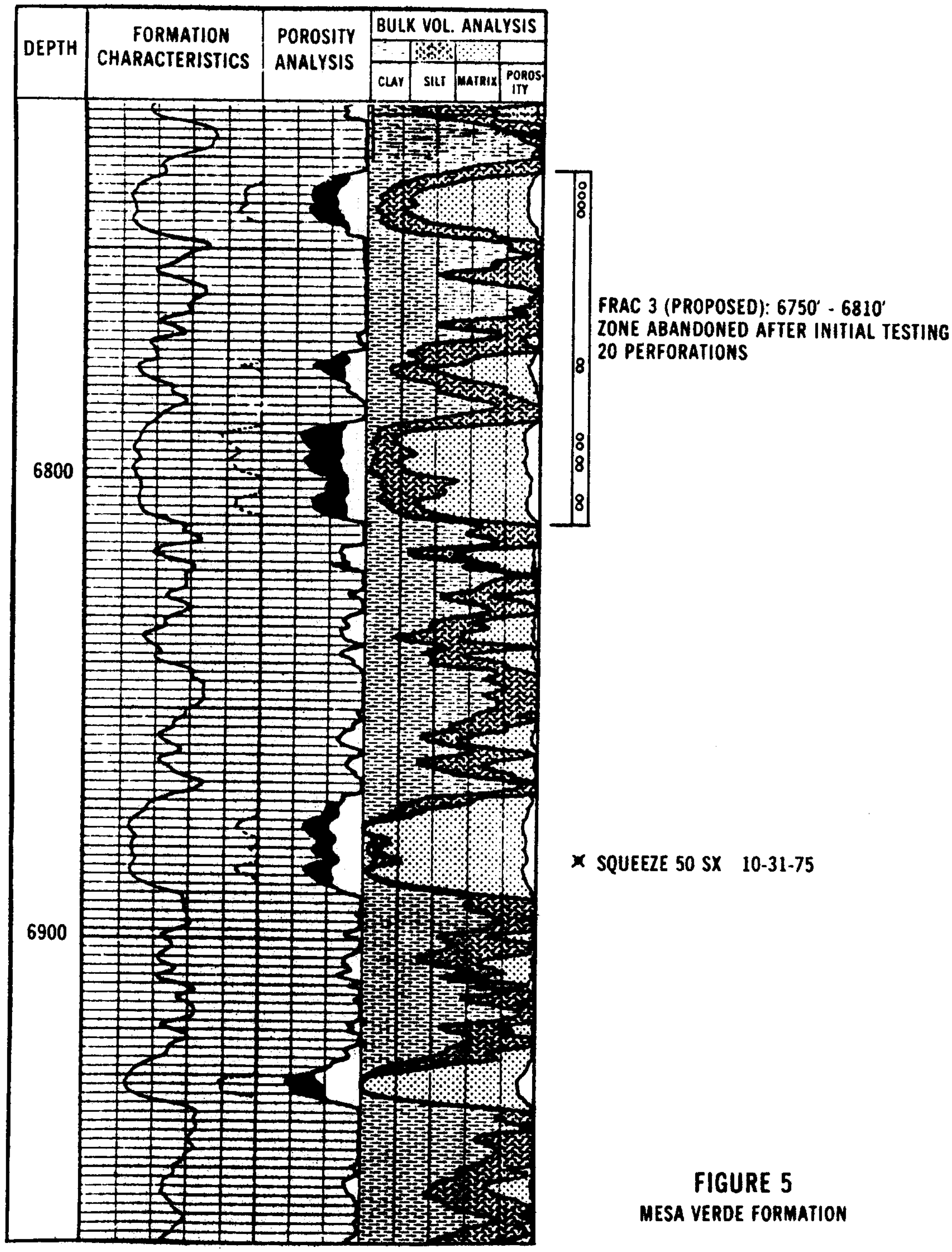


FIGURE 5
MESA VERDE FORMATION

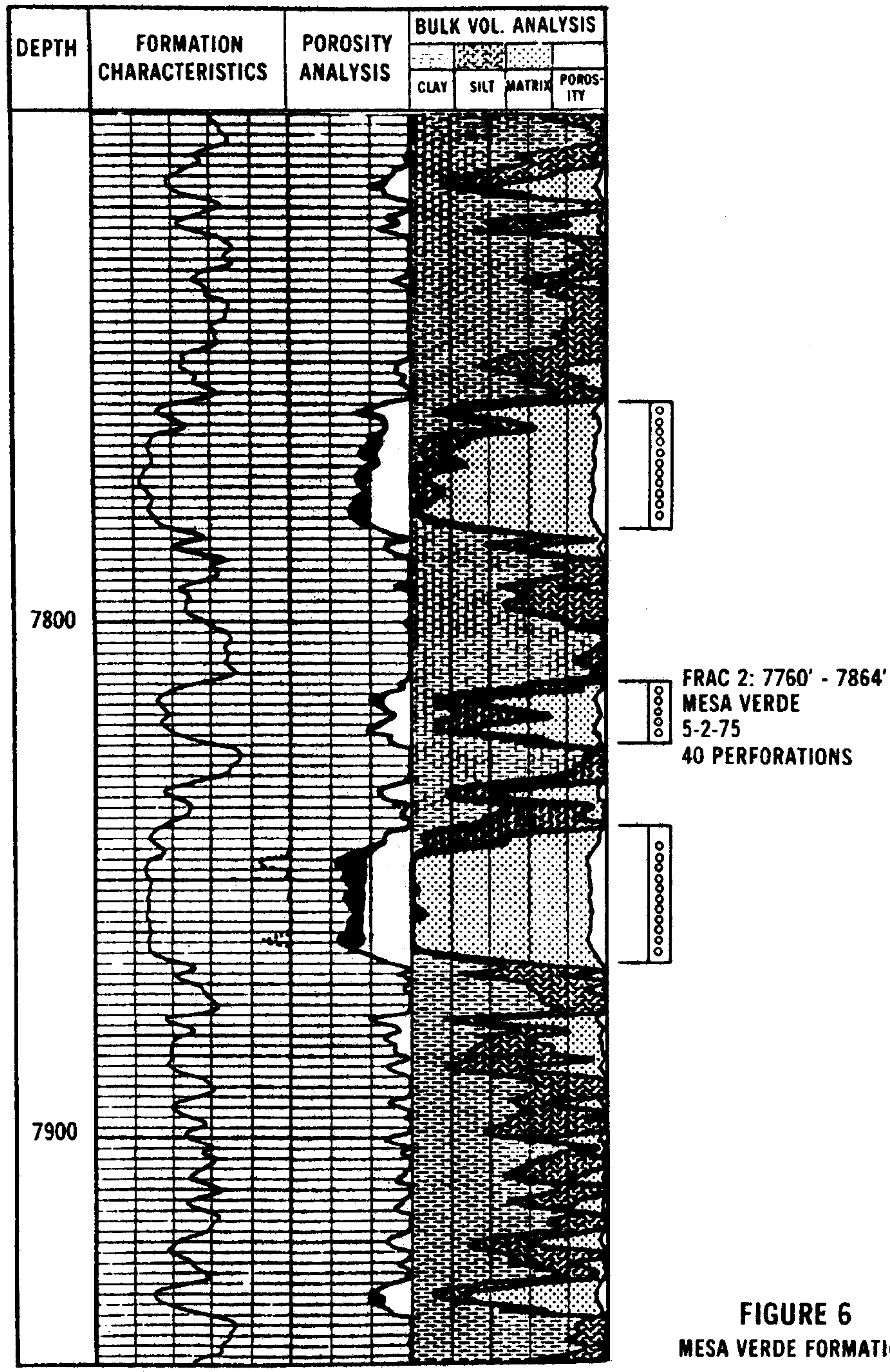
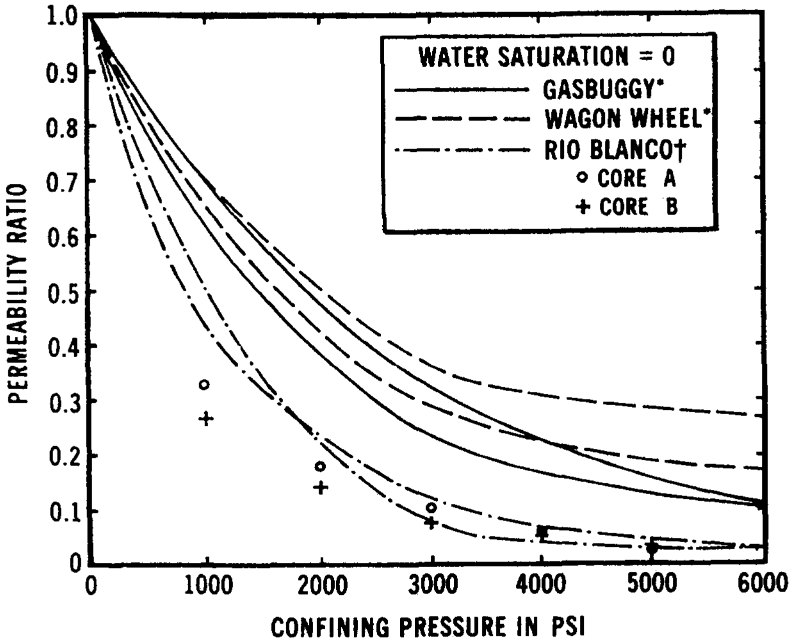


FIGURE 6
MESA VERDE FORMATION

FIGURE 7A

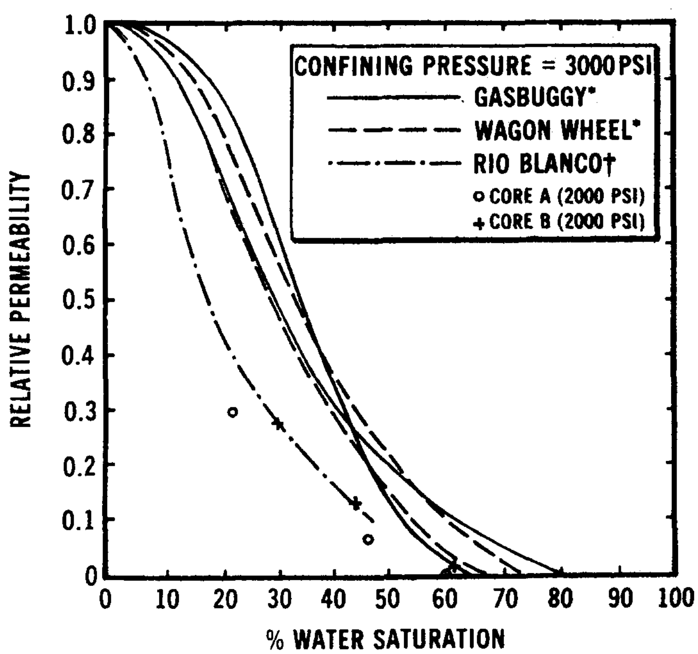
Permeability as a function of confining pressure.



*R.D. Thomas and D.C. Ward, JPT (Feb. 1972) 120-4 (USBM)
†R. Quong, UCID-16182 (Jan. 1973) 1-17 (Lawrence Livermore).

FIGURE 7B

Permeability as a function of water saturation.



*R.D. Thomas and D.C. Ward, JPT (Feb.1972) 120-4 (USBM).
†R. Quong, UCID-16182 (Jan. 1973) 1-17 (Lawrence Livermore).

DEMONSTRATION OF MASSIVE HYDRAULIC FRACTURING MESAVERDE FORMATION, PICEANCE BASIN, COLORADO

by

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Abstract

Demonstration of the efficiency and economics of massive hydraulic fracturing (MHF) in low permeability gas reservoirs is the objective of this project. It is being conducted by Mobil Research and Development Corporation with support from the United States Energy Research and Development Administration. The test site is the Piceance Basin in western Colorado. The Mesaverde Formation in this basin is more than 2500 feet thick and contains numerous gas bearing sands. Mobil has conducted one MHF test in the Basin which failed to achieve commercial production because of extremely low reservoir permeability.

The current test is in the Piceance Creek Federal Unit, Section 13, T2S, R97W, Rio Blanco County, Colorado. The well has been drilled, logged, and cased to 10,800 feet. Cores were taken at 8840-8500 and 9940-10,000 feet. Standard core analysis gives porosity of the sands less than 10% and specific permeability less than 0.1 md. Logs of the Mesaverde Formation in the test well are similar in character to those obtained in the nearby well No. 54-13.

The lowest interval containing sands suspected to be of reservoir quality has been perforated from 10,549 to 10,680 feet. Gas inflow rate after perforating was estimated at 250 MCF per day, declining to about 100 MCF per day after flowing for about two days.

If additional testing shows the interval to be suitable for MHF, it will be fractured with about 600,000 pounds of sand carried by a cellulose gel. Additional intervals will be tested for suitability for MHF and up to six fracturing treatments performed. Completion of the project is scheduled for late 1978.

Prepared for the U.S. Energy Research and Development Administration under Contract No. EY-76-C-08-0678.

DEMONSTRATION OF MASSIVE HYDRAULIC FRACTURING

MESAVERDE FORMATION, PICEANCE BASIN, COLORADO

INTRODUCTION

Demonstration of the commercial feasibility of massive hydraulic fracturing (MHF) in the Mesaverde Formation of the Piceance Basin, Colorado, is the purpose of this project. Mobil Research and Development Corporation (Mobil) and the U.S. Energy Research and Development Administration (ERDA) are jointly funding the project. It is generally recognized that vast quantities of natural gas are present in the Mesaverde Formation in the Rocky Mountain Province. The Mesaverde is more than 2500 ft. thick in the Piceance Basin and contains numerous gas-bearing sands. Mobil's prior efforts to develop this resource and plans for the current project have been discussed in a previous paper[1]. Lack of commercial success by Mobil, and others[2], in the Piceance Basin is attributed to the extremely low permeability of the Mesaverde sands.

Site of the Mobil-ERDA test is the Piceance Creek Field which is located on a large structure in the northeastern part of the Basin. Limited test data from two previous Mesaverde penetrations in the Field indicate that at least some of the Mesaverde sands have properties which are favorable for application of MHF[1].

PROGRESS OF THE PROJECT

Drilling and Casing

The test well is in Section 13, T2S, R97W, Rio Blanco County, Colorado. The well was drilled and cased by Signal Drilling Company, Rig No. 5 in 68 days, beginning April 2, 1977. Seven inch casing was set to near the total depth of 10,800 feet and cemented from T.D. to about 8,100 feet, in a single stage, using a high-strength, light-weight cement.

Coring

Cores were taken in the intervals 8440-8500 and 9940-10,000 ft. Approximately one-half of the cored material is classified as sandstone. Standard core analysis shows that porosity varies from about 5 to 10%, averaging about 8%. Specific permeability of all samples is less than, or equal to, 0.1 md. Core analysis results are shown in Table I. Tests of permeability under confining stress conditions have been performed on selected samples; these results are shown in Table II. Permeability of these samples is also being measured under simulated formation conditions of confining stress and water saturation, but the results are not yet available. Although these data are quite limited, the results suggest that in-situ permeability of the sands represented by these samples is in the micro-darcy range.

Logging

Open-hole logs included; dual-induction with SP, Compensated Sonic with γ-ray, Compensated Density and Neutron Porosity, and 4-Arm Caliper. All logs were run to 10,600 ft., the original planned depth. A good mud gas show near 10,600 ft., lead to a decision to drill to 10,800 ft. Induction and Sonic logs were run over this additional interval.

The log characteristics are similar to those recorded in near-by well No. 54-13. Some of the sands can be correlated from well to well; a majority of the sands can not, suggesting that the extent of most sand lenses is less than about 2000 ft. (The distance between the surface location of these two wells is about 1700 ft.)

Core data were used to calibrate the porosity logs. Log derived porosity of the sands varies from about 5 to 12% with a few thin intervals having porosity up to 15%. Water saturation is very difficult to determine due to uncertainty in R_W. None of the sands can be said with confidence to have 100% water saturation and no formation water samples have been obtained which are known to be free of contamination, either by fluids introduced through the wellbore or by water condensed from produced gas. Because of this uncertainty, net pay can only be determined by flow tests. The logs are being made available to commercial log information service companies.

Testing

Intervals which contain promising sands will be perforated, broken down with a small amount of fluid pumped at fracturing pressure, and flow tested. In addition to the usual flow rate and pressure buildup data, a combination noise and temperature log will be run to determine the location and approximate amount of gas flow.

The first zone tested is at 10,549-10,680 ft. This 131-ft. interval contains some 60 ft. of "sand". The entire interval was perforated with 49 jet shots. The Borehole Televiewer (BHTV) was run to determine the number of these shots which penetrated the casing. The results show 35 positive holes and 7 probable holes. Natural flow from these perforations was 250 MCF/day declining to about 100 MCF in two days.

A breakdown treatment was performed with 5000 gal. of 2% KCl pumped at 8 bbl/min; 70 balls were dropped during the treatment but ball-off was not achieved. Peak flow rate after the test was about 400 MCF/day, declining rapidly. A pressure buildup shows kh = 0.3; skin about -4; these results are shown in Figure 1.

Fracturing

A decision has been made to fracture the interval 10,549-10,680 ft. even though it does not have the desired 0.5 md-ft. This decision was based on the following considerations:

1. The zone is somewhat thinner than anticipated and its permeability is in the range deemed acceptable, i.e., equal to or greater than 0.005 md.

2. The 0.5 md-ft criterion may be too restrictive because it was based on calculations of economics which assumed a lower gas price than that which will probably be obtained.

3. The zone has relatively good log-derived properties and exhibited the best mud gas show obtained in the well.

4. A fracture treatment would provide valuable data for use in evaluation of test data from shallower zones.

5. Sequential upward perforating and testing, without fracturing, places serious mechanical constraints on subsequent fracturing of the lower, bypassed zones, if this should prove desirable.

The fracture treatment has been designed to accomplish several objectives:

1. To positively prop the fracture over most of its height, since the top-most sand appears to be the best one in the interval.

2. To frac the entire interval by the limited-entry technique.

3. To obtain a propped fracture long enough to obtain a high degree of stimulation of lenses assumed to be of the order of 1000 ft. in total length but short enough to reduce the chances of the fracture propagating out of the zone.

4. To test the effectiveness of a relatively low cost treatment in this formation using an aqueous fluid.

The treatment selected to accomplish the above objectives calls for 600,000 pounds of 20/40 mesh sand carried by a 40 pound/1000 gallons cellulose gel at 60 barrels per minute. Details of the treatment are given in Table III. The treatment is scheduled for June 22.

FUTURE PLANS

After fracturing the well will be flowed at a measured rate for at least three days then shut in for a buildup for at least twice the flow period. Noise-temperature logs will be run during the flow period to determine the points of gas influx and the approximate amount of flow at each point.

Following fracturing and flow testing of the first zone, it will be plugged off and another zone will be selected for testing. The same procedure will be used in testing of additional zones as for the first one, i.e., perforate, run BHTV, breakdown with KCl, flow, run noise-temperature log, perform pressure buildup. Suitability of the zone for MHF will be determined from the test data and from the results of the frac job on the first zone. If the zone is found suitable for MHF, it will be fractured and tested in the same manner as the first zone. If the zone tested is determined to be not suitable for MHF additional zones will be similarly tested until a suitable zone is found. It is estimated that as many as 6 intervals will be fractured. Present plans call for 3 frac jobs in 1977 and 3 in 1978.

ACKNOWLEDGEMENTS

The contributions to this project of many employees of Mobil Oil Corporation and Mobil Research and Development Corporation are gratefully acknowledged. Special thanks are due to R. H. Lasater, W. J. Dudleson, D. H. Smith, W. L. Medlin, M. K. Strubhar, E. E. Glenn, W. F. Baldwin, and A. B. Craig. Permission to publish this paper has been granted by Mobil Research and Development Corporation.

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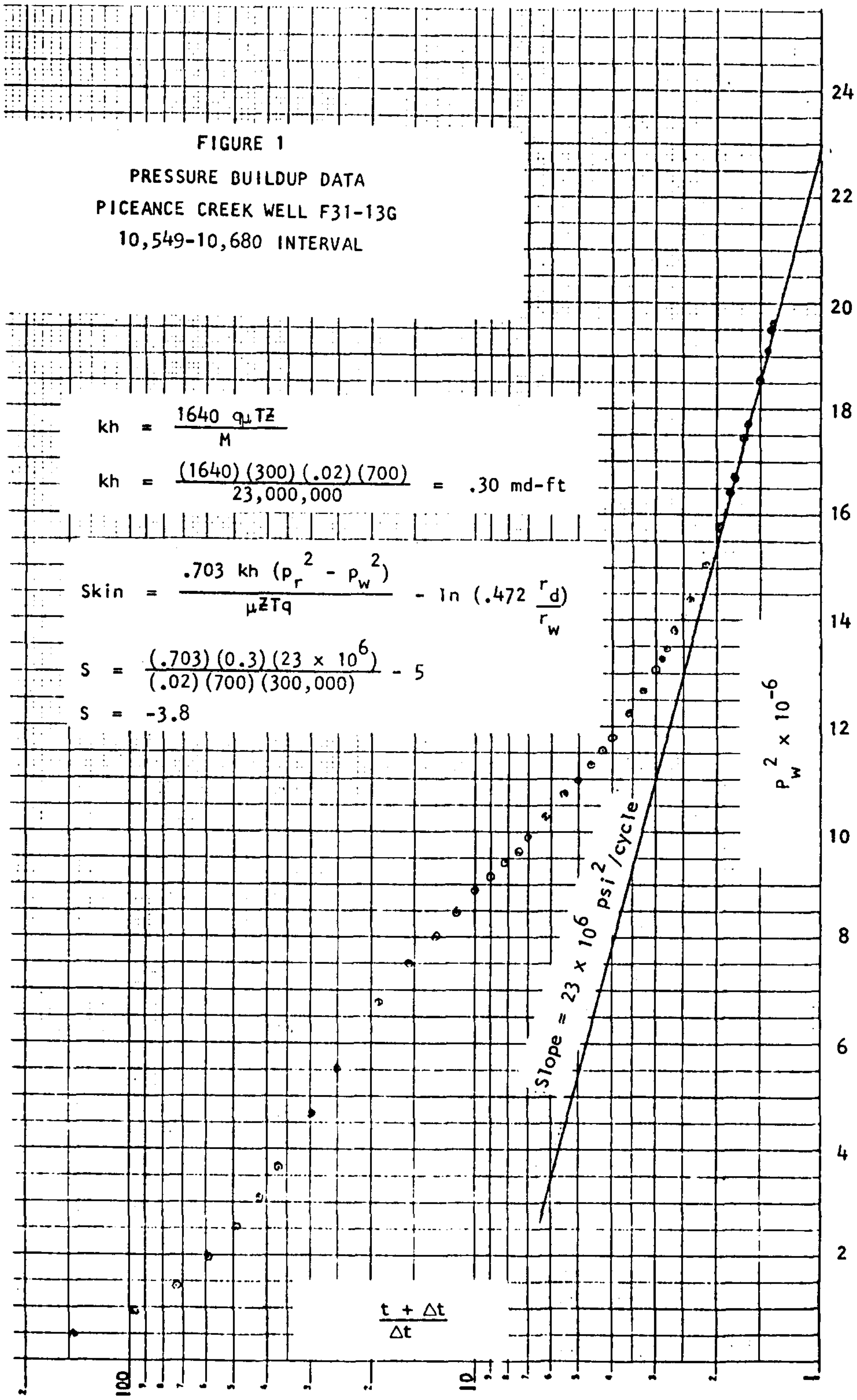

FIGURE 1
PRESSURE BUILDUP DATA
PICEANCE CREEK WELL F31-13G
10,549-10,680 INTERVAL

$$kh = \frac{1640\ q \mu T Z}{M}$$

$$kh = \frac{(1640)(300)(.02)(700)}{23,000,000} = .30 \text{ md-ft}$$

$$Skin = \frac{.703\ kh\ (p_r^2 - p_w^2)}{\mu \bar{Z} T q} - \ln\left(.472\ \frac{r_d}{r_w}\right)$$

$$S = \frac{(.703)(0.3)(23 \times 10^6)}{(.02)(700)(300,000)} - 5$$

$$S = -3.8$$

TABLE I

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

MOBIL OIL CORPORATION
PICEANCE CREEK UNIT #31-13G
PICEANCE CREEK FIELD
RIO BLANCO COUNTY, COLORADO

DATE: 5/2/77
FORMATION: MESAVERDE
DRLG. FLUID: WATER BASE MUD
LOCATION: NW NE SEC. 13-2S-97W

FILE NO: 3402-8959
ENGINEER: PUGH
ELEVATION: 7278' GL

SMP. NO.	DEPTH	PERM. TO AIR MD. PLUG	POROSITY PERCENT	FLUID SATS. OIL	FLUID SATS. WTR.	GR. DEN.	DESCRIPTION
			DEAN STARK PLUG ANALYSIS				
	8440.0-43.0						SH,VF
1	8443.0-44.0	<0.1	8.4	0.0	55.9	2.69	SD,LMY,SLTY,SHY,VF
2	8444.0-45.0	<0.1	9.1	0.0	56.1	2.70	SD,LMY,SLTY,SHY,VF
3	8445.0-46.0	<0.1	9.6	0.0	56.7	2.68	SD,LMY,SLTY,SHY,VF
4	8446.0-47.0	<0.1	8.1	0.0	54.6	2.70	SD,V/LMY,SL/SHY,VF
5	8447.0-48.0	<0.1	7.7	0.0	55.6	2.69	SD,V/LMY,SL/SHY,VF
6	8448.0-49.0	<0.1	2.7	0.0	59.0	2.69	LM,SDY,SL/SHY,VF
7	8449.0-50.0	<0.1	4.4	0.0	53.0	2.69	LM,SDY,SL/SHY,VF
8	8450.0-51.0	<0.1	2.9	0.0	53.4	2.71	LM,SHY,VF
9	8451.0-52.0	<0.1	4.9	0.0	54.9	2.70	LM,SDY,SHY,VF
	8452.0-60.0						SH,SLTY,VF
10	8460.0-61.0	<0.1	5.5	0.0	61.8	2.70	SD,V/LMY,SHY
11	8461.0-62.0	<0.1	6.2	0.0	48.2	2.70	SD,V/LMY,SH STKS
12	8462.0-63.0	<0.1	7.7	0.0	51.4	2.65	SD,V/LMY,LIG
13	8463.0-64.0	<0.1	7.7	0.0	40.3	2.70	SD,V/LMY,SL/SHY
14	8464.0-65.0	<0.1	8.6	0.0	45.9	2.68	SD,LMY,SLTY,SL/SHY
15	8465.0-66.0	<0.1	8.5	0.0	50.5	2.68	SD,LMY,SLTY,SL/SHY
16	8466.0-67.0	<0.1	8.2	0.0	55.4	2.69	SD,LMY,SLTY,SL/SHY
17	8467.0-68.0	<0.1	7.8	0.0	58.6	2.69	SD,LMY,SLTY,SHY,VF
	8468.0-92.0						SH,VF
18	8492.0-93.0	<0.1	7.8	0.0	48.5	2.66	SD,V/LMY,SLTY,LIG
19	8493.0-94.0	<0.1	6.5	0.0	71.5	2.69	SD,LMY,SLTY
20	8494.0-95.0	<0.1	9.2	0.0	64.7	2.67	SD,LMY,SLTY,SL/LIG
21	8495.0-96.0	<0.1	6.3	0.0	69.9	2.70	SD,LMY,SLTY,SH STKS
22	8496.0-97.0	<0.1	8.5	0.0	69.5	2.68	SD,V/LMY,SLTY,LIG
23	8497.0-98.0	<0.1	9.5	0.0	66.1	2.67	SD,V/LMY,SLTY,LIG

TABLE I

(Continued)

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

MOBIL OIL CORPORATION — DATE: 5/2/77 — FILE NO: 3402-8959
PICEANCE CREEK UNIT #31-13G — FORMATION: MESAVERDE — ENGINEER: PUGH

SMP. NO.	DEPTH	PERM. TO AIR MD. PLUG	POROSITY PERCENT	FLUID SATS. OIL	FLUID SATS. WTR.	GR. DEN.	DESCRIPTION
24	8498.0-99.0	<0.1	5.0	0.0	77.7	2.68	SD,LMY,SLTY,LIG
25	8499.0-00.0	<0.1	4.6	0.0	68.2	2.69	SD,LMY,SLTY,LIG
	8500.0-43.0	DRILLED					
	9943.0-47.0						SH,SLTY,SL/LMY
26	9947.0-48.0	<0.1	5.0	0.0	69.9	2.70	SD,V/LMY,SL/SHY
27	9948.0-49.0	<0.1	7.6	0.0	52.0	2.68	SD,SL/LMY,SLTY,SHY
28	9949.0-50.0	<0.1	8.1	0.0	50.4	2.66	SD,SL/LMY,SL/SHY
29	9950.0-51.0	<0.1	6.8	0.0	59.3	2.68	SD,SL/LMY,SL/SLTY
30	9951.0-52.0	<0.1	5.1	0.0	55.3	2.69	SD,V/LMY
31	9952.0-53.0	<0.1	7.5	0.0	58.5	2.68	SD,LMY
32	9953.0-54.0	<0.1	6.9	0.0	54.0	2.67	SD,LMY,SL/SLTY,SL/SH
33	9954.0-55.0	<0.1	9.0	0.0	51.0	2.67	SD,LMY,SL/SHY
34	9955.0-56.0	<0.1	9.2	0.0	45.9	2.67	SD,LMY,SL/SHY
35	9956.0-57.0	<0.1	8.1	0.0	59.3	2.67	SD,LMY,SL/SHY
36	9957.0-58.0	0.1	9.4	0.0	46.9	2.67	SD,LMY,SL/SHY
37	9958.0-59.0	<0.1	8.4	0.0	43.1	2.67	SD,LMY,SL/SLTY,SHY
38	9959.0-60.0	<0.1	7.3	0.0	61.0	2.68	SD,LMY,SL/SHY
39	9960.0-61.0	<0.1	9.3	0.0	42.2	2.67	SD,LMY,SL/SHY
40	9961.0-62.0	<0.1	8.7	0.0	49.7	2.68	SD,LMY,SL/SHY
41	9962.0-63.0	<0.1	8.2	0.0	53.4	2.68	SD,LMY,SL/SHY
42	9963.0-64.0	<0.1	8.9	0.0	49.6	2.68	SD,LMY,SL/SHY
43	9964.0-65.0	<0.1	8.9	0.0	49.1	2.68	SD,LMY,SL/SHY
44	9965.0-66.0	<0.1	8.3	0.0	55.9	2.68	SD,LMY,SL/SHY
45	9966.0-67.0	<0.1	9.4	0.0	48.4	2.68	SD,LMY,SL/SHY
46	9967.0-68.0	<0.1	8.7	0.0	52.5	2.68	SD,LMY,SL/SHY
47	9968.0-69.0	<0.1	8.7	0.0	45.1	2.69	SD,LMY,SL/SHY
48	9969.0-70.0	<0.1	8.3	0.0	48.0	2.68	SD,LMY,SL/SHY
49	9970.0-71.0	<0.1	8.9	0.0	45.8	2.68	SD,LMY,SL/SHY
50	9971.0-72.0	<0.1	7.4	0.0	48.4	2.68	SD,LMY,SL/SHY
	9972.0-79.0						SH,SL/LMY

<u>TABLE I</u>

(Continued)

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

MOBIL OIL CORPORATION | DATE: 5/2/77 | FILE NO: 3402-8959
PICEANCE CREEK UNIT #31-13G | FORMATION: MESAVERDE | ENGINEER: PUGH

SMP. NO.	DEPTH	PERM. TO AIR MD. PLUG	POROSITY PERCENT	FLUID SATS. OIL	FLUID SATS. WTR.	GR. DEN.	DESCRIPTION
	9979.0-80.0	LOST CORE					
	9980.0-83.0						SH,SL/SDY
51	9983.0-84.0	<0.1	2.7	0.0	80.9	2.69	LM,SDY,SL/SHY
52	9984.0-85.0	<0.1	4.6	0.0	53.8	2.69	SD,V/LMY,SL/SHY
53	9985.0-86.0	<0.1	4.7	0.0	60.3	2.70	SD,V/LMY,SL/SHY
54	9986.0-87.0	<0.1	5.0	0.0	57.0	2.68	SD,V/LMY,SL/SHY
55	9987.0-88.0	<0.1	5.3	0.0	66.0	2.68	SD,V/LMY,SL/SHY
	9988.0-89.0						SH,LMY,SDY
56	9989.0-90.0	<0.1	4.0	0.0	56.7	2.69	SD,V/LMY,SL/SHY
	9990.0-92.0						SH,SL/SDY
57	9992.0-93.0	<0.1	4.4	0.0	46.5	2.69	SD,V/LMY,SL/SHY
58	9993.0-94.0	<0.1	6.5	0.0	46.3	2.69	SD,V/LMY,SL/SHY
59	9994.0-95.0	<0.1	6.9	0.0	43.9	2.69	SD,V/LMY,SL/SHY
60	9995.0-96.0	<0.1	7.3	0.0	43.8	2.69	SD,V/LMY,SL/SHY
61	9996.0-97.0	<0.1	6.6	0.0	45.9	2.69	SD,V/LMY,SL/SHY
62	9997.0-98.0	<0.1	8.3	0.0	40.1	2.68	SD,LMY,SL/SHY
63	9998.0-99.0	<0.1	7.5	0.0	48.1	2.67	SD,SL/LMY,SL/SHY
64	9999.0-00.0	<0.1	7.7	0.0	47.8	2.67	SD,SL/LMY,SL/SHY

TABLE I

(Continued)

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE SUMMARY

Company MOBIL OIL CORPORATION
Well PICEANCE CREEK UNIT NO. F31-13G
Page 4 of 4 File 3402-8959

DEPTH	HORIZONTAL PERMEABILITY, Md.	POROSITY	SATURATION OIL	SATURATION WATER	GRAIN DENSITY
8443- 8448	<0.1	8.6	0.0	55.8	2.69
8448- 8452	<0.1	3.7	0.0	55.1	2.70
8460- 8468	<0.1	7.5	0.0	51.5	2.69
8492- 8498	<0.1	8.0	0.0	65.0	2.68
8498- 8500	<0.1	4.8	0.0	73.0	2.69
9947- 9954	<0.1	6.7	0.0	57.1	2.68
9954- 9972	<0.1	8.6	0.0	49.7	2.68
9983- 9988	<0.1	4.5	0.0	63.6	2.69
9992-10000	<0.1	6.9	0.0	45.3	2.68

TABLE II

PERMEABILITY OF SELECTED SAMPLES UNDER
CONFINING STRESS AND SIMULATED RESERVOIR CONDITIONS

Confining Pressure-Psi \ Depth Ft.	Permeability in Md			
	8463	8468	9953	9960
500	.0159	.0190	.0187	.0316
1000	.0128	.0140	.0151	.0246
2000	.0083	.0089	.0094	.0141
3000	.0054	.0051	.0064	.0100
5000	.0030	.0025	.0038	.0048
Porosity %	7.7	7.8	4.7	7.3

TABLE III

Gel: 40 lbs. of cellulose polymer/1000 gal

Sand: 20-40 mesh

Pump Rate: 60 barrels/min.

Treatment Schedule:

	Incremental Vol., Gal.	Sand, lbs/gal	Sand, pounds
	10,000	0 (pad)	0
	150,000	2	300,000
	80,000	$2\frac{1}{2}$	200,000
	33,000	3	100,000
	15,000	0 (flush)	0
Totals	288,000		600,000

Calculated Frac Properties:

Created Length: 1700 ft. (wellbore to tip)
Propped Length: 700 ft. (wellbore to tip)
Created Width: 0.55 in.
Propped Width: 0.38 in.
Propped Height: 130 ft.

Data Used in the Calculations Above Include:

Frac height (assumed): 150 ft.
Fox field (effective) stress: 2000 psi
Porosity: 10%
Young's Modulus: 5×10^6
K' (consistency index of frac fluid): 0.001
N' (flow behavior index of frac fluid): 0.75

THE RULISON FIELD
MASSIVE HYDRAULIC FRACTURING EXPERIMENT

By:

Miles Reynolds, Jr.
Austral Oil Company Incorporated
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Houston, Texas 77002

ABSTRACT

The Rulison Field, Garfield County, Colorado, has seven producing gas wells completed in the Mesaverde formation. One of these wells, the Federal #3-94, was selected for a massive hydraulic fracturing experiment. The Federal #3-94 has a producing history of more than ten years.

The experimental fracture treatment was applied in two stages treating separately the gross perforated intervals from 6198' to 6363' (Stage 1) and 5170' to 5630' (Stage 2). Approximately 485,000 gallons of gelled water, 1,070,000 pounds of sand and 500 standard cubic feet of nitrogen per barrel were used. A brief cleanup flow period was allowed between stages. The fracture treatments were performed in August 1976.

The treatment was designed to extend a fracture approximately 1400' from the wellbore with a propped fracture width of 0.176 inches. The production increase was expected to range from 5.5 to 6.2 times the pre-treatment rate of 35 thousand standard cubic feet per day.

The results of the massive hydraulic fracturing treatment were poor. Production of gas was enhanced by a factor of less than 2. The average flow rate during early 1977 was about 50 thousand cubic feet per day. The lack of success is attributed to both low reservoir permeability and a restricted reservoir due to sand lenticularity.

Prepared for the Energy Research and Development Administration Under Contract No. EY-76-C-08-0679.

I. History of Rulison Field

The Rulison Field (Figure 1) discovery well, Juhan #1, Garfield County, Colorado, was completed in the gas bearing Mesaverde formation in 1952. Subsequent drilling through 1956 resulted in six (6) additional Mesaverde well completions.

Two additional Mesaverde wells were completed by Austral Oil Company in 1966 to gather data for the Project Rulison feasibility study. Project Rulison was a joint industry-government experiment to assess the feasibility of stimulating the flow and recovery of natural gas from the Mesaverde formation by fracturing with a contained nuclear explosive. The project was completed in 1971. (See References)

One of the wells which was completed in 1966, the Federal #3-94, was selected for the massive hydraulic fracturing experiment described herein.

II. Federal #3-94; Completion and Production History

The Federal #3-94 was completed in the Mesaverde formation with a 7" casing liner fully cemented from 4432' to 6505'. Perforations in the 7" casing span the interval from 5170' to 6353' and are grouped as follows:

1. 5170-5434'; 20 holes (selective perforations)
2. 5484-5630'; 20 holes (selective perforations)
3. 6198-6205'; 14 holes (2 holes/foot)
4. 6333-6353'; 20 holes (1 hole/foot)

Each group of perforations was initially (original completion) treated with the following volumes of fluid (water inhibited with 2% potassium chloride) and propping agent:

Perforation Group	Gallons Fluid	Pounds 20-40 Mesh Sand
1	50,568	46,200
2	81,900	83,538
3	42,000	42,000
4	53,300	60,000

This treatment resulted in an initial producing potential of 595 thousand standard cubic feet of gas per day. Upon subsequent connection to a pipeline, the well exhibited a behavior typical of the wells in this field (Figure 2). A steady decline in both flow rate and pressure were observed through 1970. Thereafter the flow rate was governed by the fluctuations in pipeline pressure. As of July 30, 1976, and prior to MHF treatment, cumulative production from the well was 181.228 million standard cubic feet.

The selection of this well for a massive hydraulic fracturing experiment was on the basis of (1) being in mechanically sound condition, (2) having several years of production history, and (3) being located in a part of the field where considerable information is known about the characteristics of the gas reservoir, i.e., porosity, permeability, thickness, water saturation.

III. Massive Hydraulic Fracture Treatment Design

Basic reservoir and well data (Figure 3) were submitted to the two major oil field service companies in order to develop the basic fracturing treatment proposal. The final accepted design employed a two-stage treatment separating perforations in Group 1 and 2 from Group 3 and 4 (see list above).

The lower perforations (Group 1 and 2) were isolated by means of tubing (2-7/8" OD) and packer and were treated with approximately 205,000 gallons of fluid containing 420,000 pounds of sand (140,000 pounds 20/20 mesh, 280,000 pounds 10/20 mesh) and 500 standard cubic feet per barrel of nitrogen. After a brief cleanup flow period, the lower perforations were isolated with a retrievable plug and the upper perforations (Group 3 and 4) were treated with approximately 280,000 gallons of the same fluid containing approximately 650,000 pounds of sand (350,000 pounds 20/40 mesh, 300,000 pounds 10/20 mesh) and 500 standard cubic feet of nitrogen. The frac fluid used was Dowell's water base controlled gel (trade name YF4G). Sand concentrations as high as 4 pounds per barrel fluid were achieved.

The fracture treatment was designed to extend propped fracture length approximately 1400' from the wellbore. The propped fracture width was calculated to be 0.176 to 0.179 inches.

Production increase was expected to range from 5.5 to 6.2 times greater than the pre-treatment rate of approximately 35 thousand standard cubic feet of gas per day.

IV. Post-Treatment Results

Following the execution of the fracturing treatments, the well was recompleted with a string of 2-3/8" OD production tubing suspended without a packer to a depth just above the perforations. The well was flowed to a pit for a period of several days prior to reconnection to the pipeline. A considerable amount of swabbing was required to remove large quantities of frac fluid and enable the well to flow. After recovery of approximately 50%-60% of the frac fluid, the well was able to flow intermittently into the pipeline. Additional swabbing was required on occasion. The post-treatment results are shown in Figure 4.

V. Analysis of Fracture Treatment Results

The results of this massive hydraulic fracturing treatment have not been encouraging. The relatively low natural reservoir energy coupled with continued influx of fracturing fluids into the wellbore have prevented the well from flowing on a sustained basis. Installation of a production packer above all perforations and later between perforation Groups 2 and 3 did not result in improved well performance.

From the post-treatment data it would appear that production of gas has been enhanced by a factor of less than 2.

VI. Cost of Program

The direct costs incurred for this experiment are as follows:

1.	Fracturing services	$ 251,000*
2.	Rig	34,000*
3.	Equipment, tool rentals	17,000
4.	Water, hauling	9,000
5.	Other trucking costs	7,000
6.	Completion services	4,000
7.	Location preparation	2,000*
8.	Other miscellaneous costs	1,000
9.	Project management costs	12,000
	TOTAL	$ 337,000

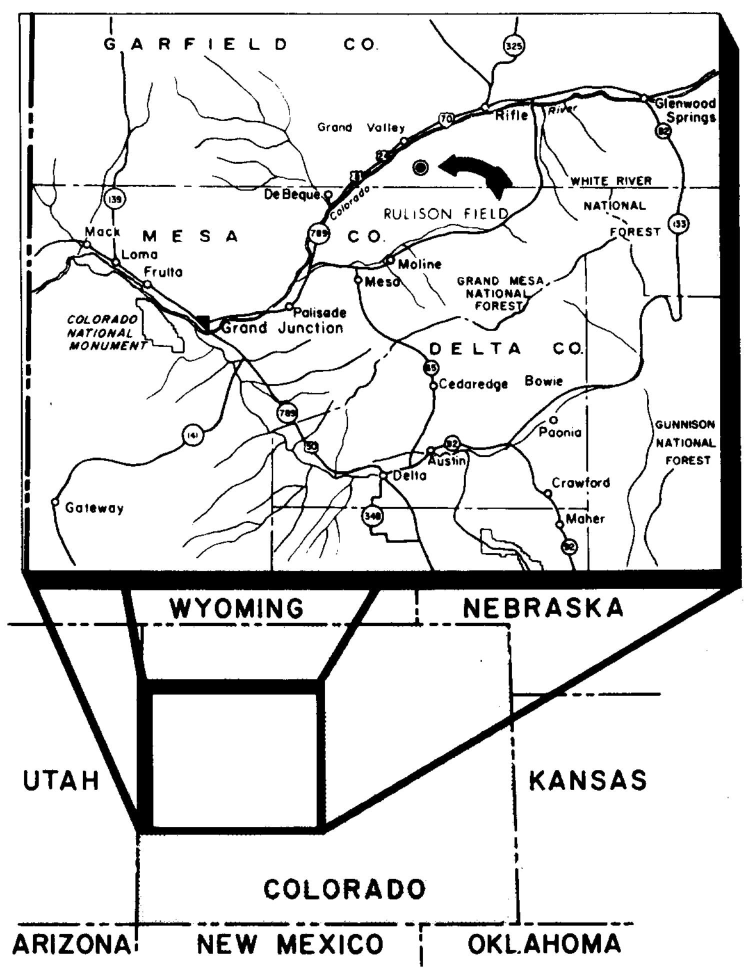
* Reimbursed by ERDA

VII. Conclusions

It is concluded that the application of massive hydraulic fracturing techniques in the Federal #3-94 Well has not been successful in stimulating the flow and recovery of natural gas from the Mesaverde formation. The lack of success is attributed primarily to both low reservoir permeability and a restricted reservoir due to sand lenticularity. Only a slight increase in flow rate was achieved, but is overwhelmed by the cost to achieve this increase.

References

The Project Rulison Open File System contains feasibility studies, project data and safety contractor reports. Such files have been established by E.R.D.A. in Las Vegas, Nevada, Denver, Colorado and Bartlesville, Oklahoma. Copies of all material can also be obtained from E.R.D.A., Division of Technical Information, Oak Ridge, Tennessee.



Map Showing Location of Rulison Field

FIGURE 1

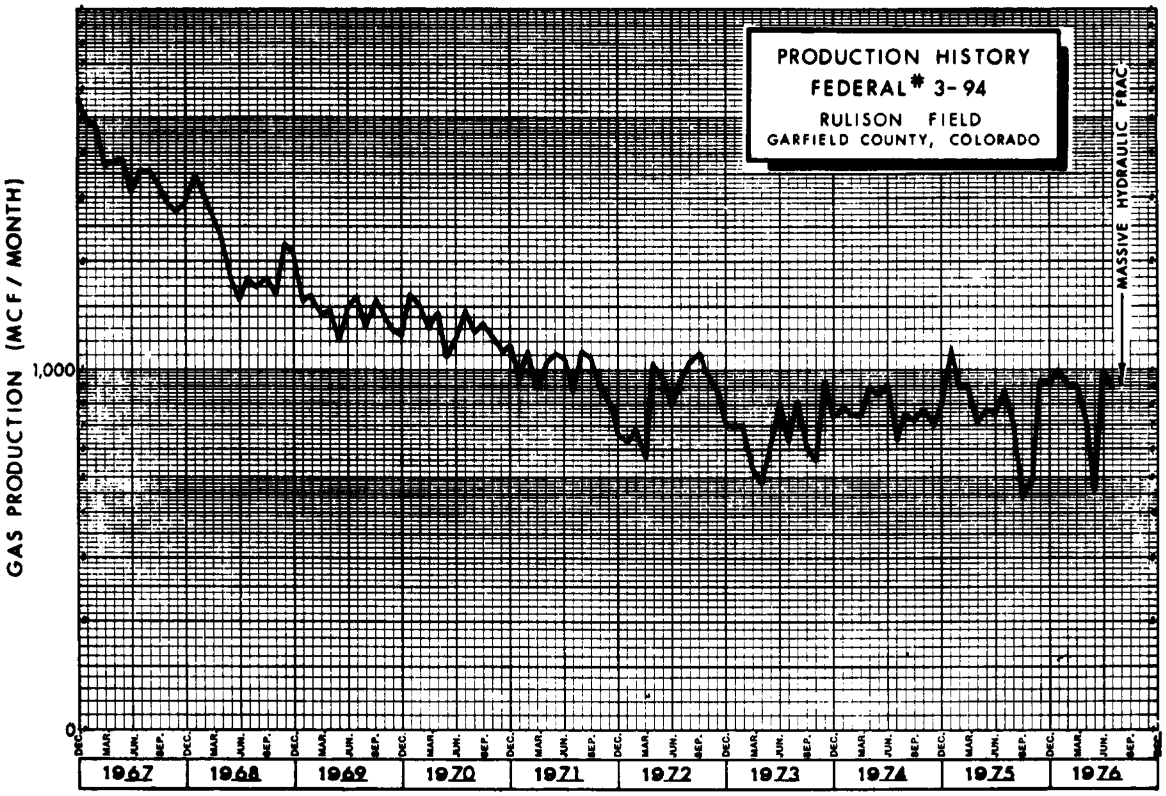


FIGURE 2

Frac Interval 5170-5434'

Gross Zone	Perforated Zone	BHTP PSI	BHP* PSI	Ø %	k md	Gross Sand	Net Sand	No. Perfs.
5156 - 5185'	5170-5186.5'	3937	1500	12	.01*	29'	21'	5
5284 - 5327'	5304-5330'	3937	1500	8	.01*	43'	19' 10'	8
5337 - 5368'	5359-5368.5'	3937	1500	5	.01*	31'	5' 13'	2
5404 - 5434'	5416-5434'	3937	1500	11	.01*	30'	30'	6
Frac Interval 5484 - 5630'								
5455 - 5517'	5484.5-5586' 5498-5517'	4077	1500	13 13.5	.01* .01*	62'	13' 29'	2 5
5528 - 5564'	5539-5542' 5554-5564'	4077	1500	11	.01*	36'	34'	2 3
5580 - 5586'	5588'	4077	1500	9*	.01*	6'	6'	1
5594 - 5640'	5606-5630'	4077	1500	11	.01*	46'	46'	7
Frac Interval 6198-6205'								
5176 - 5194' 6212 - 6222'	6198-6205'	5430	1500	9*	.01*	18' 10'	14' 10'	14
Frac Interval 6333-6353'								
6309 - 6360'	6333-6353'	5259	1500	13.5	.01*	51'	37'	20

*Average

Figure 3

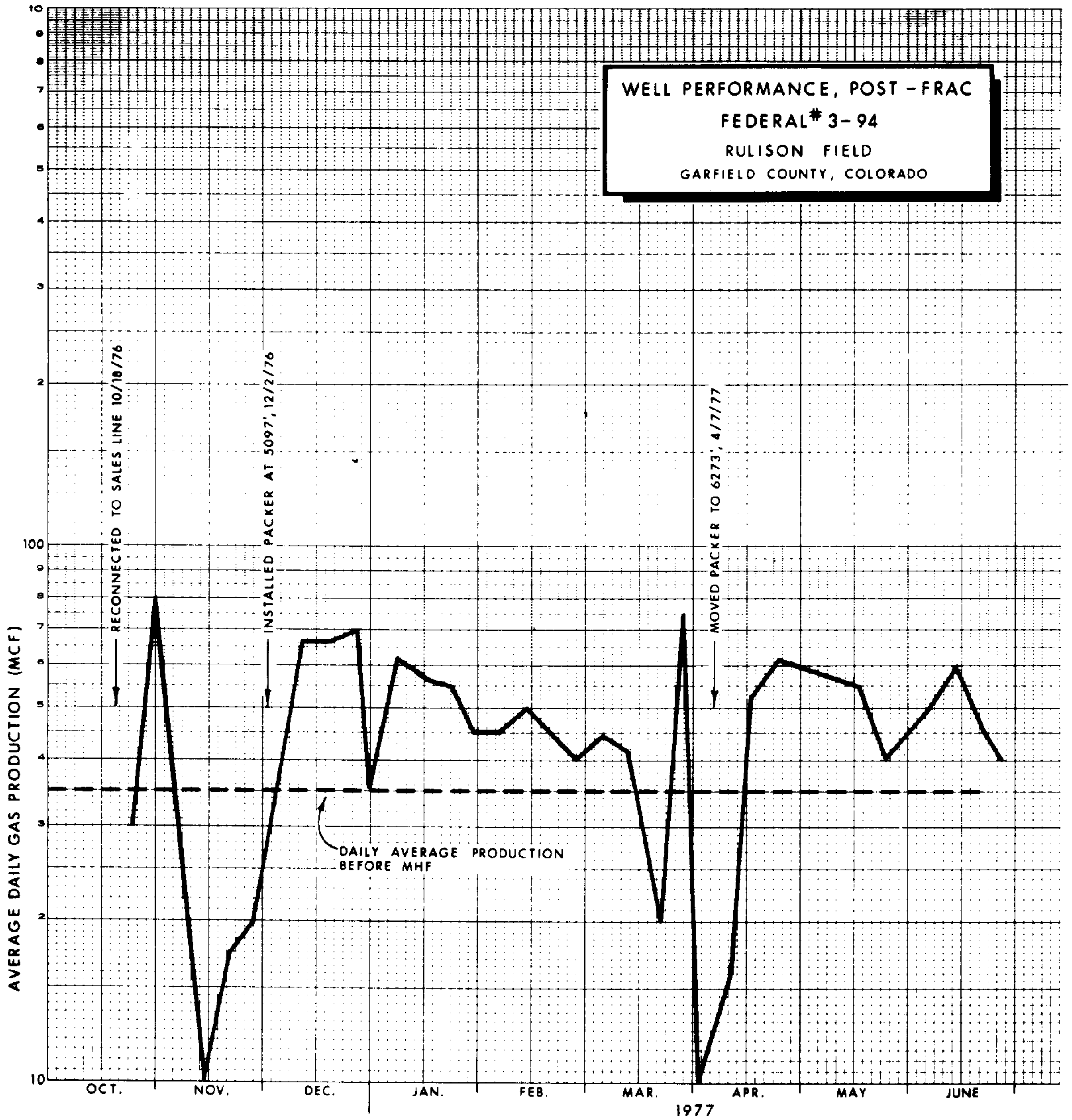

WELL PERFORMANCE, POST - FRAC
FEDERAL # 3-94
RULISON FIELD
GARFIELD COUNTY, COLORADO
AVERAGE DAILY GAS PRODUCTION (MCF)
RECONNECTED TO SALES LINE 10/18/76
INSTALLED PACKER AT 5097', 12/2/76
MOVED PACKER TO 6273', 4/7/77
DAILY AVERAGE PRODUCTION BEFORE MHF
10
100
OCT.
NOV.
DEC.
JAN.
FEB.
MAR.
APR.
MAY
JUNE
1977

FIGURE 4

PACIFIC TRANSMISSION SUPPLY COMPANY
SAND RIDGE MESAVERDE MASSIVE HYDRAULIC FRACTURE PROJECT
UINTAH COUNTY, UTAH

by

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ABSTRACT

Pacific Transmission Supply Company and the Energy Research and Development Administration contracted to evaluate approximately 2500 feet of Mesaverde formation in the Uinta Basin of northeastern Utah.

The contract proposal called for continuous drillstem testing of the Mesaverde, coring of 400 to 500 feet of the formation to determine rock characteristics, continuous mud logging, and open-hole logs, including a Schlumberger Experimental Acoustic log to attempt to determine rock mechanical properties. Further, special core work was to be done to determine in-situ stress field and in-situ permeability and porosity insofar as possible. Mini-fracturing of selected intervals were then to be performed in the open-hole before running casing to help determine in-situ rock stress fields. Impression packers were to be run after mini-fracturing to determine fracture direction. Analyses of data obtained during drilling were to be made to help in design of three massive hydraulic fractures in sandstones of the basal, middle and upper Mesaverde. The fractures would only be performed if gas producing sandstones could be shown to aggregate a gas transmissibility of 0.5 millidarcy-feet in the lower Mesaverde and 1.0 millidarcy-feet in each of the middle and upper Mesaverde.

The test well was drilled and reached a total depth of 9282 feet on January 21, 1977. Production casing was run, and subsequently eight sandstone zones were perforated to test for feasibility of gas production. These eight zones were selected from critical analyses of drillstem tests, gas log and open-hole logs. Although all zones showed gas production in small amounts,

Prepared for ERDA under Contract No. EY-76-C-08-0680

each zone also produced water in varying amounts. Analyses of data obtained from flow tests of the various perforated zones showed none of the zones to possess gas transmissibility of sufficient magnitude to meet the contract criteria. Therefore, no massive hydraulic fractures were proposed or performed, and those parts of the contract pertaining to fracturing in the Mesaverde were terminated.

INTRODUCTION

Pacific Transmission Supply Company and the United States of America, through the Energy Research and Development Administration, contracted to drill a well and evaluate approximately 2500 feet of the Mesaverde formation in the Uinta Basin located in northeastern Utah.

A federal government study indicated in-place reserves of 200 to 400 billion cubic feet of gas per section in the tight Mesaverde sands.

Pacific Transmission Supply Company made a geologic study of the Mesaverde formation underlying approximately 160 townships of the eastern portion of the Uinta Basin to determine the more favorable areas of porosity trends for drillsite selection. It was anticipated that the Mesaverde would contain sands with at least 300 feet net log porosity of eight percent or greater. Ownership of the lands within the area is predominantly federal. Pacific Transmission Supply Company proposed that a well be drilled to evaluate sandstones within the lower, middle and upper Mesaverde formation. It was anticipated that a total of three massive hydraulic treatments, one each in the lower, middle and upper parts of the formation, would be performed.

The test well, 23-25 Federal, was located in the NE/4 SW/4 Section 25, Township 8 South, Range 23 East, Uintah County, Utah. The well was spudded November 4, 1976 and reached a total depth of 9282 feet on January 21, 1977. During the drilling, the Mesaverde formation was almost continuously drillstem tested with 18 tests being run or attempted starting at a depth of 6560 feet. Of the 18 tests, five were misruns. The well actually encountered 574 feet of gross sand with log porosities of eight percent or higher. The calculated water sands greatly exceeded our expectations with only a few zones calculating 80 percent or less.

After 5-1/2 inch casing was run and cemented, all drillstem tests, cores and log data were evaluated to determine which sands would be perforated, acidized and tested for massive hydraulic fracturing. A total of nine sands were selected to be perforated.

Each of the sands were perforated, acidized and flow-tested separately. It was determined that none of the sands were sufficiently gas-productive to warrant treatment by massive hydraulic fracture. The wellsite phases of the Pacific Transmission Supply Company-Energy Research and Development Administration Contract were terminated on June 14, 1977.

THE CONTRACT

Pacific Transmission Supply Company and the Energy Research and Development Administration entered into Contract Number EY-76-C-08-0680 effective September 1, 1976, entitled "SAND RIDGE II PROJECT, UINTAH COUNTY, UTAH."

Pursuant to the terms of the contract, a well was to be drilled to a sufficient depth in order that the full Mesaverde section could be evaluated for possible massive hydraulic fracturing. The well was located in NE/4 SW/4 Section 25, Township 8 South, Range 23 East, Uintah County, Utah. The entire Mesaverde section (approximately 2500 feet) was to be drillstem tested, and 400 to 500 feet of cores, including some oriented cores, were to be obtained from the upper, middle and lower Mesaverde. The overlying Wasatch and Green River formations were excluded from the contract. In addition, the following open-hole logs were to be run:

(1) Dual Laterolog
(2) Compensated Neutron-Density
(3) Borehole Compensated Sonic
(4) Experimental Sonic
(5) Differential Temperature

TerraTek, Inc., Salt Lake City, Utah, was to perform special core studies in the field of selected intervals of both regular and oriented cores. These studies were to include core relaxation measurements to determine the direction of the two principal horizontal In Situ stresses. In addition, small scale hydraulic fractures were to be created in the well bore to determine the magnitude and orientation of in situ stress orientation. The fractures created were to be analyzed by use of impression packers.

Laboratory studies of the cores were made of potential reservoir zones as well as the adjacent rocks. Dry densities, grain densities and connected pore volumes were determined as well as saturation and unfilled gas volumes. Triaxial compression tests were to be conducted at simulated in situ conditions.

Frac fluid-rock interaction studies using various fracture fluids currently being used by industry were made, again under in situ simulation to characterize the loss in permeability of reservoir rocks due to the application of hydraulic fracture fluid. The effect of hydraulic fracture fluid on the permeability of the propped fracture with various sand concentrations and sizes was also studied.

After running production casing, sandstone members of the Mesaverde in the lower, middle and upper portions were to be perforated, acidized and flow-tested to determine gas flow capacity of the perforated sands. Massive hydraulic fractures were to be done only if gas producing sandstones indicated an aggregate gas transmissibility of 0.5 millidarcy feet in the lower Mesaverde and 1.0 millidarcy feet in each of the middle and upper Mesaverde.

DRILLING OPERATIONS

Well 23-25 Federal was spudded November 4, 1976. A 17-1/2 inch hole was drilled to 300 feet, and 13-3/8 inch surface casing was set. A 12-1/4 inch hole was drilled to a depth of 3410 feet where 9-5/8 inch intermediate casing was run. Since the well is in an oil shale withdrawal area, the intermediate casing was required by the U. S. Government to protect oil shales of the Green River formation. A 7-7/8 inch hole was drilled from 3410 feet to a total depth of 9282 feet, reached January 21, 1977. Five and one-half inch production casing was run to 8965 feet. No serious mechanical or hole problems were experienced during the drilling of the well; however, considerable time was spent drillstem testing and coring.

A total of 18 drillstem tests were run in the Mesaverde. Of the 18 tests, five were misruns because of packer seat failures. A total of 12 cores were cut. The cored intervals totaled 469 feet of which 427 feet were recovered. Recovery was 91 percent. Of the 12 cores, four were oriented. The oriented cores were obtained so that TerraTek Laboratories could perform stress relaxation measurements.

Two open hole mini-frac experiments were performed by TerraTek personnel at depths of 8822-8830 feet and 9017-9032 feet. Only the mini-frac of the interval 9017-9032 feet was successful. An impression packer was run in an attempt to impress the created fracture in the interval 9017-9032 feet to determine the fracture orientation, but the attempt was unsuccessful.

A manned mud logging unit with hotwire and gas chromatograph was operated to record gas shows during all drilling operations from the base of the surface pipe to total depth. At total depth, the following open hole logs were run:

(1) Dual Laterolog
(2) Compensated Neutron Density-Gamma Ray
(3) Borehole Compensated Sonic-Gamma Ray
(4) Experimental Sonic
(5) Differential Temperature

PERFORATING, ACID BREAKDOWN AND FLOW TESTS

The top of the Mesaverde formation was picked at 6410 feet in the Federal 23-25 well. The formation had an overall thickness of 2556 feet with the base of the formation being the same as the top of the Mancos shale at 8984 feet.

Data from all logs, cores and drillstem tests were analyzed to select sandstone intervals to be perforated, broken down with acid and flow-tested. The results of the flow-tests were to be used to determine the feasibility of establishing commercial production be means of stimulating with massive hydraulic fractures. Analysis of the data indicated the following intervals to have the best prospects:

8824-8832 feet	Lower Mesaverde	(Castlegate)
7793-7801 feet	Middle Mesaverde	(Neslan)
6800-6814 feet	Upper Mesaverde	(Farrar)
6755-6764 feet	Upper Mesaverde	"
6603-6624 feet	" "	"
6558-6576 feet	" "	"
6524-6536 feet	" "	"
6458-6466 feet	" "	"
6438-6444 feet	" "	"

All of the above zones were perforated at the depths as shown with jet shots. The zones were individually broken down with acid and tested individually. Zone separation was achieved by using packers, permanent bridge plugs or retrievable bridge plugs. The zones are again listed showing number of perforations, size of acid breakdown and flow-test results. The flow-tests generally exceeded a week's duration to obtain stable flow:

Zone	No. of Perfs	Acid	Flow Rate After Recovered Load Fluid
8824-8832'	16	12,000 gallons	Small amount gas, 204 BWPD
7793-7801'	16	1,500 "	6 MCF/D plus 20 BWPD
6800-6814'	14	1,500 "	6 MCF/D plus 40 BWPD
6755-6764'	9	1,000 "	5 MCF/D plus 60 BWPD
6603-6624'	21	2,000 "	15 MCF/D plus 80 BWPD w/trace of oil
6558-6576'	18	2,000 "	12.6 MCF/D plus 120 BWPD
6524-6536'	12	1,500 "	17 MCF/D plus 60 BWPD
6458-6466'	8	1,000 "	17 MCF/D plus 20 BWPD
6438-6444'	6	1,000 "	10 MCF/D - no water

None of these sands or combinations of sands showed water-free gas production in sufficient quantities to warrant a massive hydraulic fracture treatment. All zones of the Mesaverde were abandoned in June. Abandonment of the Mesaverde completed the wellsite phases of the contract between Pacific Transmission Supply Company and Energy Research and Development Administration.

CONCLUSION

The Federal 23-25 well is believed to have been a well conceived project to accumulate data to evaluate approximately a 2500 foot vertical section of the Mesaverde formation for gas in the eastern part of the Uinta Basin. The data and subsequent production testing through casing showed all sands in the Mesaverde to be too tight to yield commercial gas production even with massive hydraulic fracturing. In addition, eight of the nine sands tested through casing yielded water in significant quantities which would be detrimental to attempt a completion for gas production.

REVIEW OF NATURAL BUTTES UNIT MASSIVE HYDRAULIC FRACTURING PROJECT

by

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Abstract

A Massive Hydraulic Massive Fracturing program has been initiated in the Natural Buttes Unit, a marginal gas field located in the Bitter Creek Field in the Uinta Basin of northeastern Utah. The program includes fracturing nine wells (new & old) with different combinations of types and volumes of fluid, size and amount of sand and methods of placement to find the completion procedure which is most effective in recovering gas from these low permeability sands. Fracture orientation tests will also be conducted. There is a pending program modification to allow for coring, extensive electric logging, pre-frac testing, etc., on one well. Four wells have been fractured to date under this program.

Introduction & Summary

The Tertiary Wasatch and Cretaceous Mesaverde formations underlie a major part of the Uinta Basin. These formations contain low permeability, gas saturated sands. Similiar formations occur in the adjoining Green River and Piceance Basins and the sands are also similiar to low permeability sands which occur extensively in other areas. In the area of interest the Wasatch-Mesaverde interval is from 5,000 to 9,500 feet with north-northwest regional dip of 100 feet per mile. The gross interval contains about 25 sands, that will each average about 20 feet of net sand. The angular to subangular fine grain sands are well cemented with calcareous cementing material. Fracture gradients are in the order 0.75psi/ft in the sands and 0.90 psi/ft in the shales. Porosity, water saturation

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Prepared for ERDA under Contract No. E(26-1)-681.
Figures and tables at end of paper.

and permeability are 9%, 50% and 0.1 to 0.001 md respectively. Volumetric gas-in-place is calculated at 105 BCF per 640 acre section, based on the above parameters and Pr - 3000 psi, Tr - 170°F and a gas deviation factor of 0.86. Gas Producing Enterprises Inc. (GPE) a division of Coastal States Gas Corporation is Unit Operator and Owner of 85,405 acres of Wasatch Mesaverde lease-hold rights in the Natural Buttes Unit. Based on the foregoing calculations, the Natural Buttes Unit contains 14.7 TCF of gas-in-place. The Wasatch Mesaverde sands are gas productive over a large area in the Uinta Basin and the Natural Buttes Unit is a highly prospective area for testing these low permeability sands, especially since it typifies the occurance of 600 TCF of potential gas in the Uinta, Green River and Pieance Basins. This emphasizes the importance of the larger objective of determining commercial methods of recovering gas from low permeability sands.

A program to perform nine massive hydraulic fracturing treatments over a two year period at an estimated cost of 5.1 million dollars is planned for the Natural Buttes Unit. The Energy Research and Development Administration (ERDA) will contribute 2.2 million dollars and GPE (contractor) will contribute 2.9 million dollars. The primary objective of the program is to determine a cost effective method of recovering gas from low permeability sands. This will be accomplished by testing and evaluating the following:

1. Effect of fracture length on deliverability and ultimate recoverable reserves.

2. Orientation of fractures.

3. In situ fracture conductivity created by different combinations of proppants and fracture fluids.

4. Fracture fluid efficiency in transporting sand, controlling frac height, avoiding formation damage and breaking gels after frac.

5. Spacing of fractured wells.

6. Fracture of all sands in a 3,500' gross interval including marginal and less well-developed gas-bearing sands.

7. Different methods of treatment and sand placement.

Other relative parameters will also be evaluated. All tests will be performed under field conditions and the wells will be placed on production immediately. Figure 1 shows the location of the Natural Buttes

Unit in the Uinta Basin and the relative position to other geographical areas in the Rocky Mountains. Figure 2 is a field map of the Natural Buttes Unit showing well locations, pipe lines, etc.

Program Summary

Figure 3 is a Milestone Chart showing the scheduling of the wells to be treated and the individual operations for each well. A summary of the remaining wells in the program to be tested showing estimated formation characterisitics and thicknesses, amount and type of treating materials and other information is shown on Table 1.

After each well is drilled and logged, 4½" casing is run and cemented at total depth. The prospective intervals are selected from the electric logs and a perforating and fracturing treatment program designed. The well is perforated in 2% KCl water and production tested. Water is removed by swabbing or using nitrogen if necessary. Fracturing equipment and materials are mobilized and the well is treated. Two basic placement methods have been used; (1) treat continuously in stages spearheading each stage with acid and diverting between stages with perforation ball sealers and (2) limited entry in one continuous stage. After treatment the well is flowed back to clean up and then placed on production. Down-hole surveys are run as required.

Project Status

To date four wells have been fractured under the program. Table No. 2 contains the summarized results of these fracturing treatments. The wells are discussed separately as follows:

Phase I: Natural Buttes Unit #18

Four and one half inch (4½") casing was set at 9140'. Eighteen zones were perforated over the gross interval of 6490'-8954', 4 ft/zone, 1 perf/ft. The well was blown dry with nitrogen and averaged 50 MCFD on a pre-frac production test. The well was fractured with 695,000 gals. of cross-linked, low residue guar gum fluid and 1,380,000 lbs of 20-40 sand. The treatment was pumped in nine continuous stages (designed to treat two zones per stage). Each stage was spearheaded with 1000 gals of 15% acid and the stages were diverted with perforation ball sealers. A temperature survey was run before flow-back. The well was flowed back and placed on production on September 30, 1976. The well initially produced 1500 MCFD and is now stablized at 820 MCFD. The "rate-time" production curve for this well is shown on Figure 4.

Phase II: Natural Buttes Unit #19

Four and one half ($4\frac{1}{2}$") casing was set at 9697'. Nine zones were perforated in the gross interval from 8676'-9664' with 4 ft/zone, 1 perf/ft. These zones were treated with 275,000 gals. of 40 lb. guar gum/1000 gals. fluid, 363,000 lbs. of 40-60 sand and 61,000 lbs. of 100 mesh sand. The well was flowed back immediately at a high rate. Ten zones were perforated in the gross interval from 7224'-8676' and treated with 358,000 gals. guar gum gel, 712,000 lbs. of 40-60 sand, and 72,000 lbs. of 100 mesh sand. Perforation ball sealers were used for diversion in both treatments. The well was flowed back at a high rate. A Gamma Ray Survey was run to locate radio active sand used during the treatment. The well did not clean up and it was determined that the well was producing formation water. The water was shut off by isolating with packers and the well placed on production in February, 1977. The well is currently producing about 115 MCFD. The "rate-time" production curve for this well is shown on Figure 5.

Phase III: Natural Buttes #14

This was an old well with $4\frac{1}{2}$" casing set at 8053'. The well had approximately 15 zones perforated over the gross interval from 6826'-8004' which had originally been acidized with 10,000 gals of 15% Hcl. The well was treated with 576,000 gals. of cross-linked, low residue guar gum fluid, 1,053,000 lbs. of 20-40 sand and 40,000 lbs. of 40-60 sand. During the treatment, Sandia Laboratory of Albuquerque, New Mexico (Sandia) personnel took data by measuring electrical potentials to determine fracture length and orientation. The well was flowed back, cleaned up and placed on production in May, 1977. This well had been producing for about 2 years prior to treatment and had declined to a rate of about 40 MCFD. After treatment the well produced about 790 MCFD. The "rate-time" production curve for this well is shown on Figure 6.

Phase IV: Natural Buttes #20

Four and one half inch ($4\frac{1}{2}$") casing was set at 9807'. Eight zones over the gross interval from 8498'-9476' were perforated with 20 holes for limited entry. The well was stimulated on June 22, 1977, with 309,000 gals. of cross-linked, low residue guar gum fluid and 56,000 lbs. of 100 mesh sand, 745,000 lbs. of 40-60 and 25,000 lbs. of 20-40 glass beads. During the treatment, Sandia personnel took data by measuring electric potentials to determine fracture length and orientation. Before flow-back. a Gamma Ray Log was run to locate radio active tracer sand used during the treatment. The well was placed on production in July, 1977, at a rate of about 1500 MCFD.

Results and Conclusions

The Massive Hydraulic Fracturing program is progressing satisfactorily. Final results and conclusions cannot be determined until additional procedures have been tested, verified by duplicate test stimulations and followed by production testing.

Various preliminary conclusions can be drawn from early project results. The smaller 40-60 mesh sand can be pumped into the formation at concentrations up to 5 #/gal with a low viscosity (40# guar gum/1000 gal) fluid. The best combination of fluid and sand size has not been determined. Eighteen zones have been fractured in one continuous staged treatment. Temperature logs and Gamma Ray Tracer Surveys show that over 90% of the perforated intervals are being treated. Post fracture temperature surveys indicate that twenty feet of shale thickness will act as a barrier to halt vertical fracture growth. Fracture growth generally extends above and below the sand body. Sand production has not been a major problem during flow back. Increased shut-in time before flow back reduces sand production when a high viscosity fracturing fluid is used. Sand production is not affected by the size of sand used.

The fracture length and orientation data were processed and reviewed. No definite conclusions have been determined to date. Assuming a correct interpretation, the data indicated "single wing" fractures and random fracture direction i.e., one fracture extending in one direction and another extending in a different direction. The data from Natural Buttes #20 is still being processed by Sandia.

The logistics of mobilizing materials and equipment for a massive hydraulic fracturing treatment requires careful planning, preparation and coordination. All of the treatments have been performed in a satisfactory manner.

Acknowledgment

Part of the foregoing information was included in a paper entitled Natural Buttes Unit Massive Hydraulic Fracturing Program by W. E. Spencer, Vice President of Gas Producing Enterprises, Inc., 5 Greenway Plaza Houston, Texas 77046. The paper was submitted at the Second Annual Symposium in Tulsa, Oklahoma. It is recommended that this paper be reviewed for additional background information on the Natural Buttes Unit.

This project has been a group effort. Gas Producing Enterprises' permission to publish this paper is appreciated. Energy Research & Development Administrations assistance and technical support has been a significant contribution. Frank R. Midkiff in our Denver Office is the District Superintendant in the area and R. G. "Bob" Merrill also of our Denver Office is Project Engineer. K. E. Oden of our Vernal Office is in charge of field operations.

Table 1 - Future Well Treatment Program

Fiscal Year	Well Number	Job Size	Cost	Fluid	Frac Length	Sand Type	Frac Orientation	Average Zone Quality and Net Pay	Remarks
	NBU 21	1,400,000 gals. 2,000,000 lbs.	$450,000	Final changes based on previous results.	1600'	To be determined	To be tested	$\emptyset$ = 8.8% S_w = 53% h = 500'	Comparison of log data and core data to help determine zones to be perforated. Success probability = 95+ %. Testing of cored intervals
	NB #9	To be determined	$200,000	New design, CO_2	800'	40-60	NA	$\emptyset$ = 8.5% S_w = 55% h = 400'	Old well. Success probability 60%
	NBU 22	To be determined	$400,000	Cross-linked KCl water	1500'		NA	$\emptyset$ = 8.5% S_w = 60% h = 600'	Success probability = 90+ %.
					OPTIONAL PROGRAM				
FY 1978	NBU ?	To be determined	$350,000	Finalized design	To be determined	To be determined	NA	$\emptyset$ = 9.0% S_w = 50% h = 350'	Success probability = 90+ %
	NBU ?	To be determined	$400,000	Finalized design	1500'	To be determined	NA	$\emptyset$ = 9.0% S_w = 50% h = 350'	Success probability = 90+ %

Table 2 Summary of MHF Treatments

Well	No. of Zones Perf.	Net Ft. of Pay	Average				Frac Job Size			Frac Length Ft.	Est. 1st Yr. Avg. Prod. Rate MCFD	Rec. Reserve 30 Yrs. BCF
			Net Ft Per Zone	Ø	SW	% Sd	Type of Fluid	Gals of Gel	Pounds of Proppant			
NATURAL BUTTES #18	18	224	12.5	10	48	88	VERSA FRAC	695,000	1,480,000	882	1200	4.12
NATURAL BUTTES #19	19	194	10.2	9.5	47	87	40# GUAR GUM	655,000	1,237,000	950		
NATURAL BUTTES #14	15	271	18.0	9.9	49	65	YF4-PSD	544,000	1,082,000	879		
NATURAL BUTTES #20	8	65	8.1	9.9	44	88.5	YF4-PSD	309,000	826,000	1150		

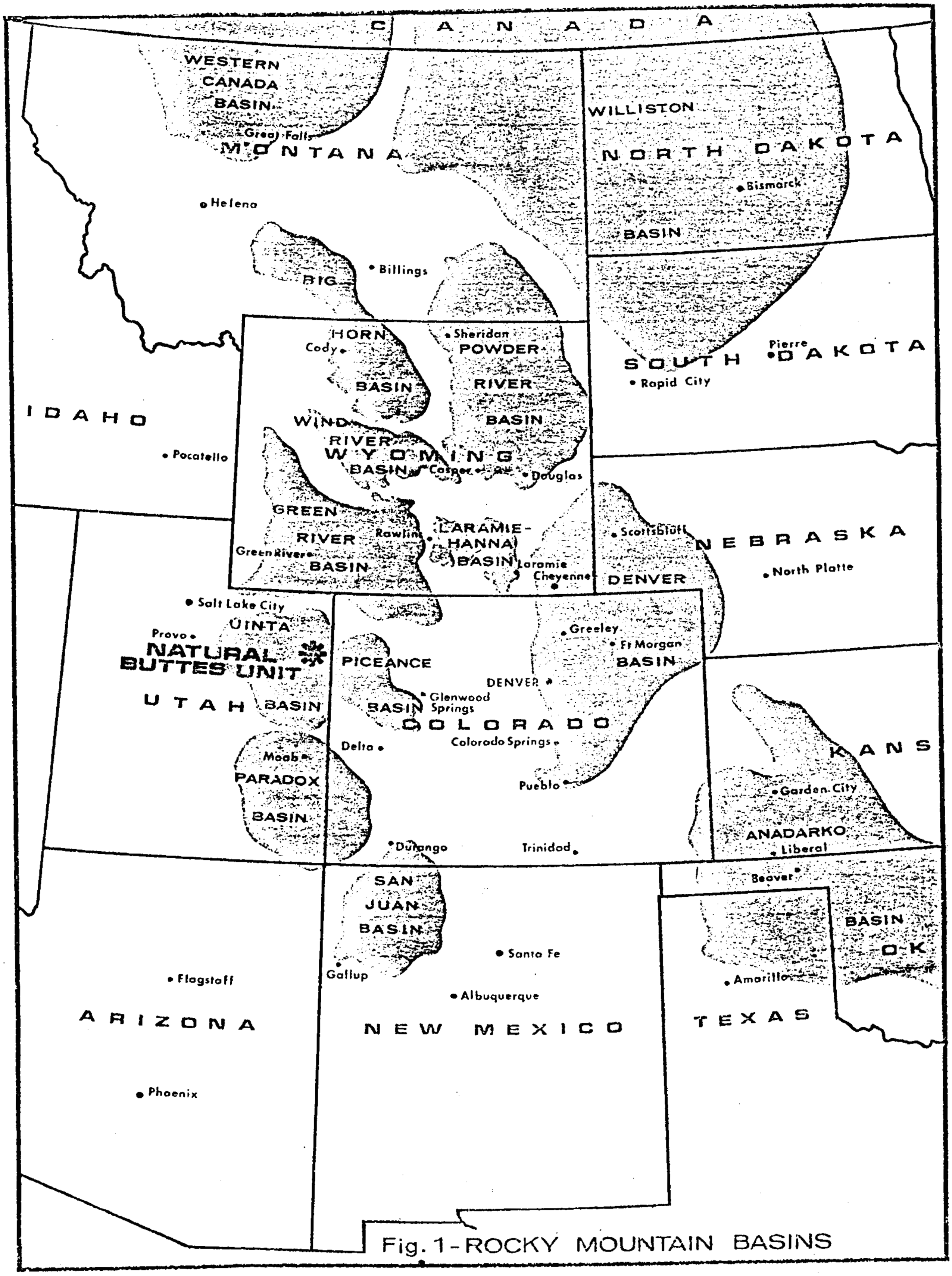
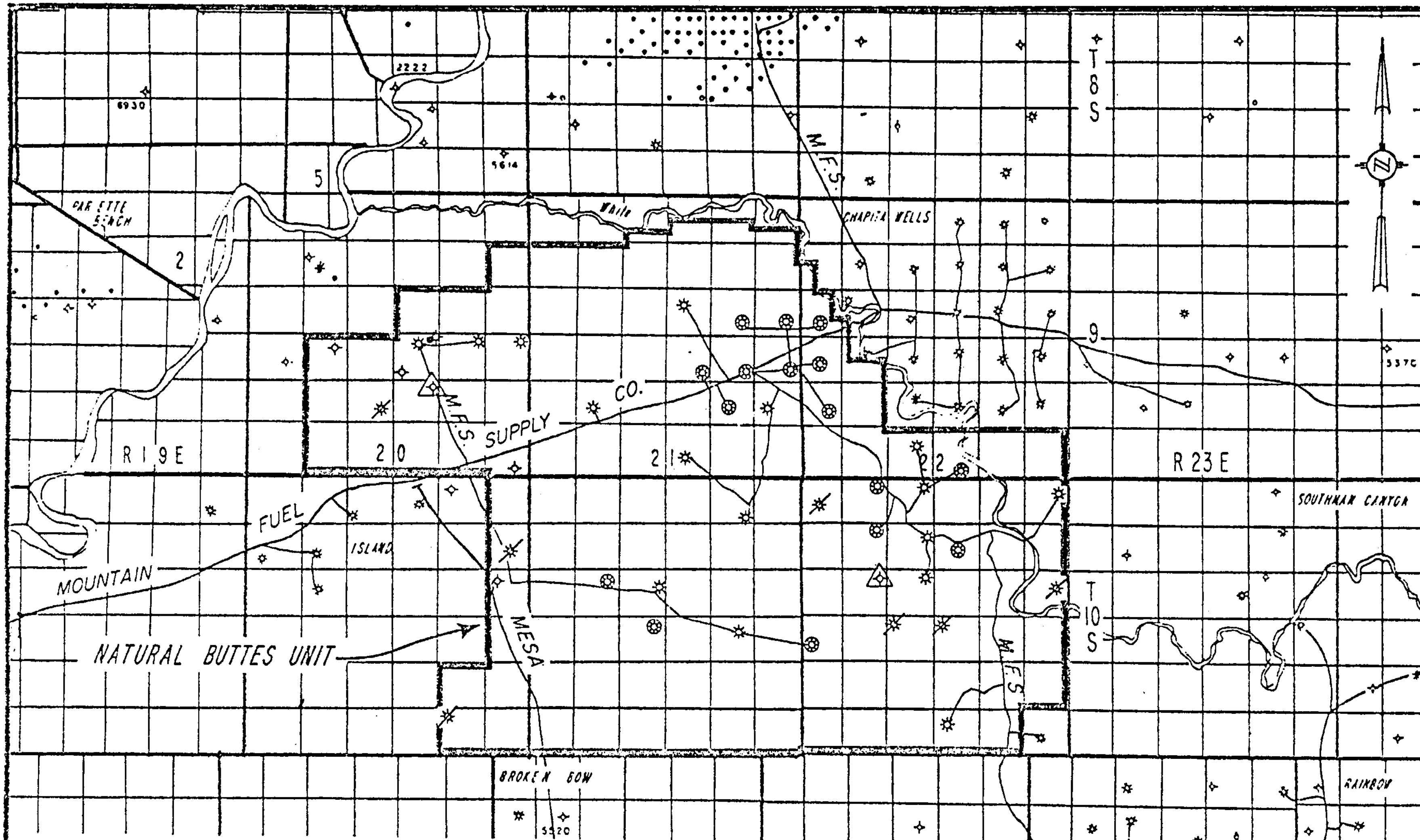


Fig. 1 - ROCKY MOUNTAIN BASINS



LEGEND

- ⊛ WASATCH-MESAVERDE GAS WELL
- △ WASATCH-MESAVERDE DRY HOLE
- ✲ WASATCH GAS WELL
- ✲ WASATCH ABANDONED GAS WELL
- ✧ DRY HOLE

GAS PRODUCING ENTERPRISES, INC.

Fig. 2 - NATURAL BUTTES UNIT
UTAH

Fig. 3 - Milestone Chart

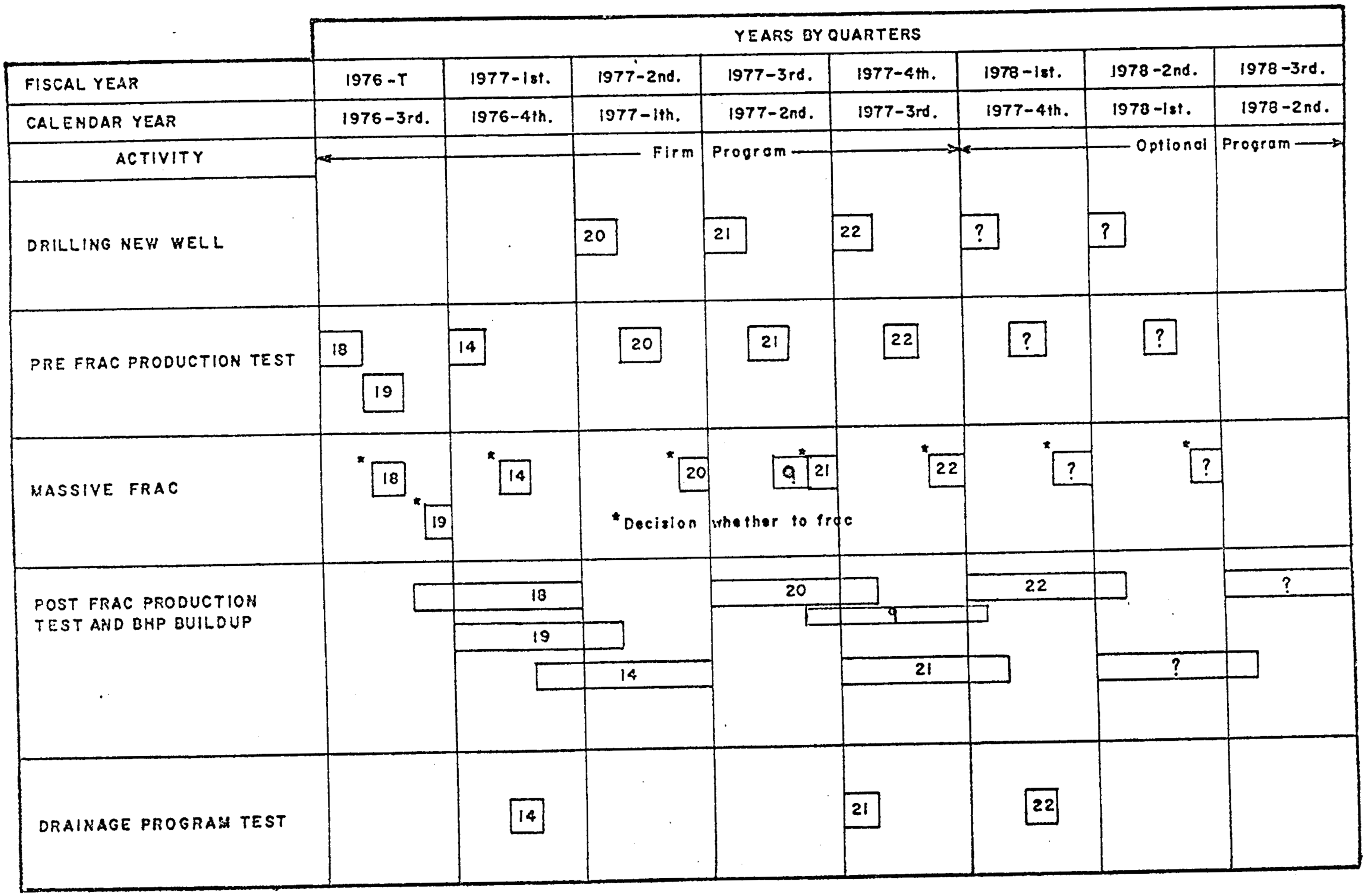


FIGURE 4

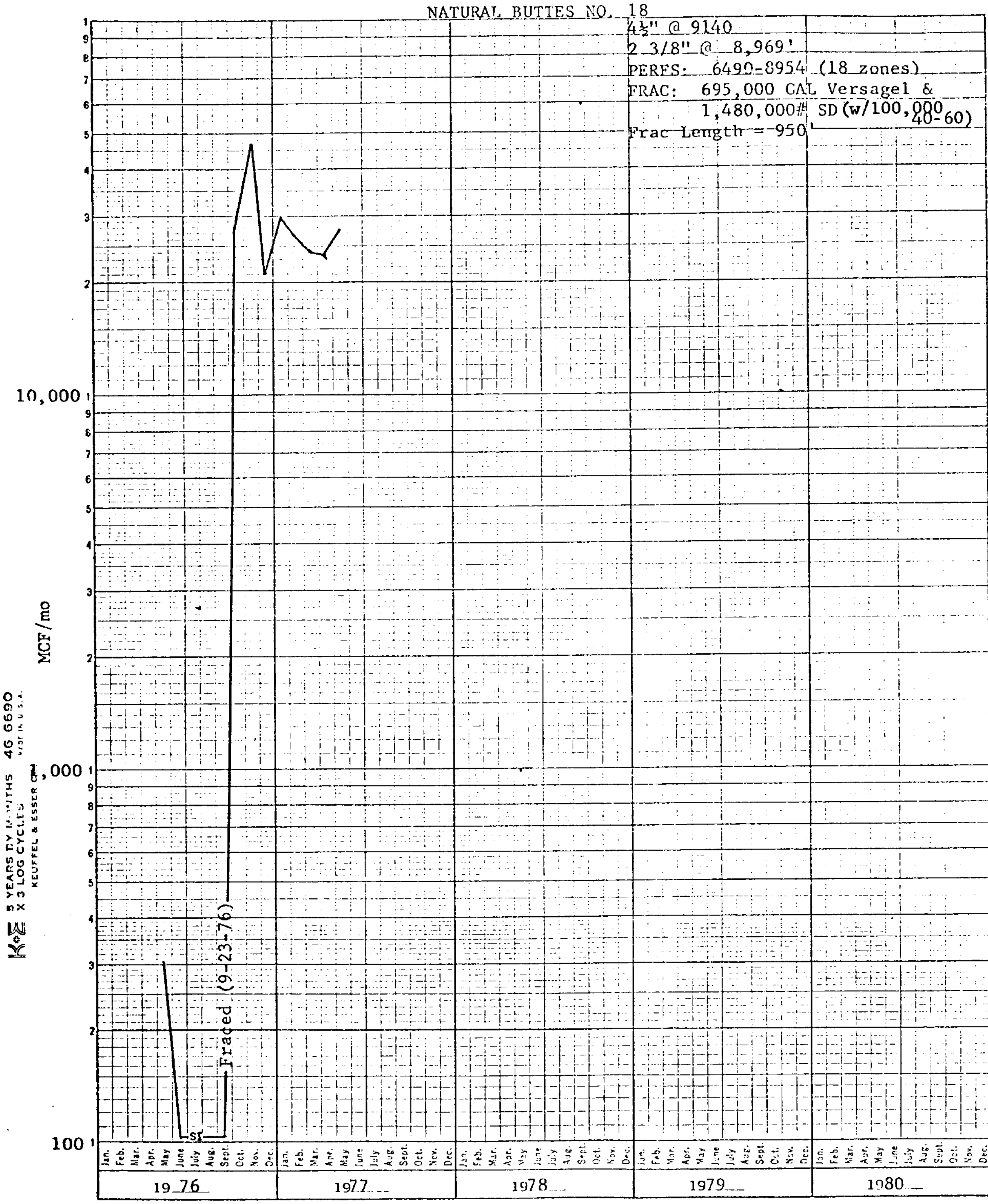

NATURAL BUTTES NO. 18
4½" @ 9140
2 3/8" @ 8,969'
PERFS: 6490-8954 (18 zones)
FRAC: 695,000 GAL Versagel &
1,480,000# SD (w/100,000 40-60)
Frac Length = 950'
10,000
1,000
100
MCF/mo
Fraced (9-23-76)
SI
Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.
1976
1977
1978
1979
1980
K+E 5 YEARS BY MONTHS X 3 LOG CYCLES 46 6690
KEUFFEL & ESSER CO.

FIGURE 5

NATURAL BUTTES NO. 19

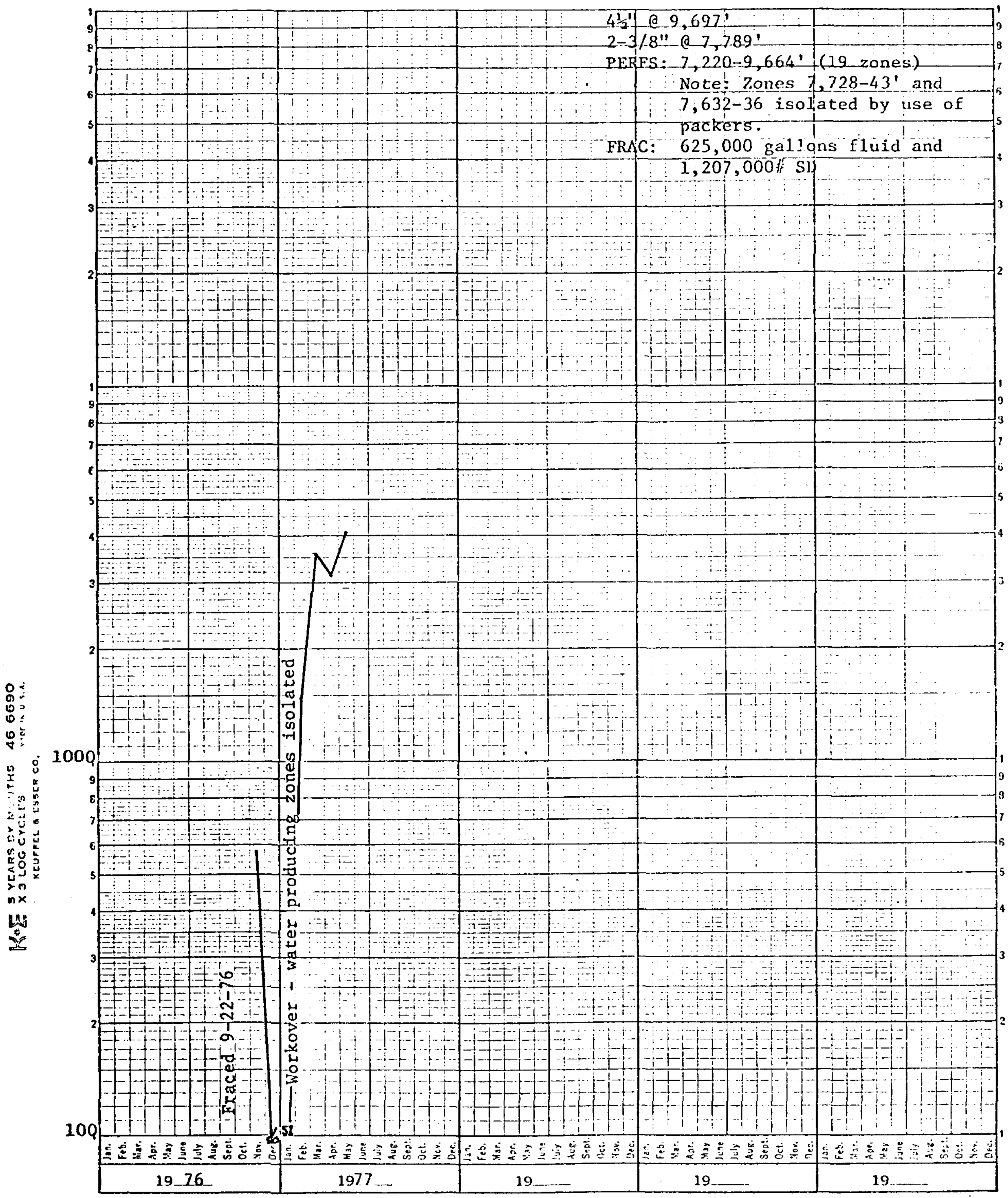
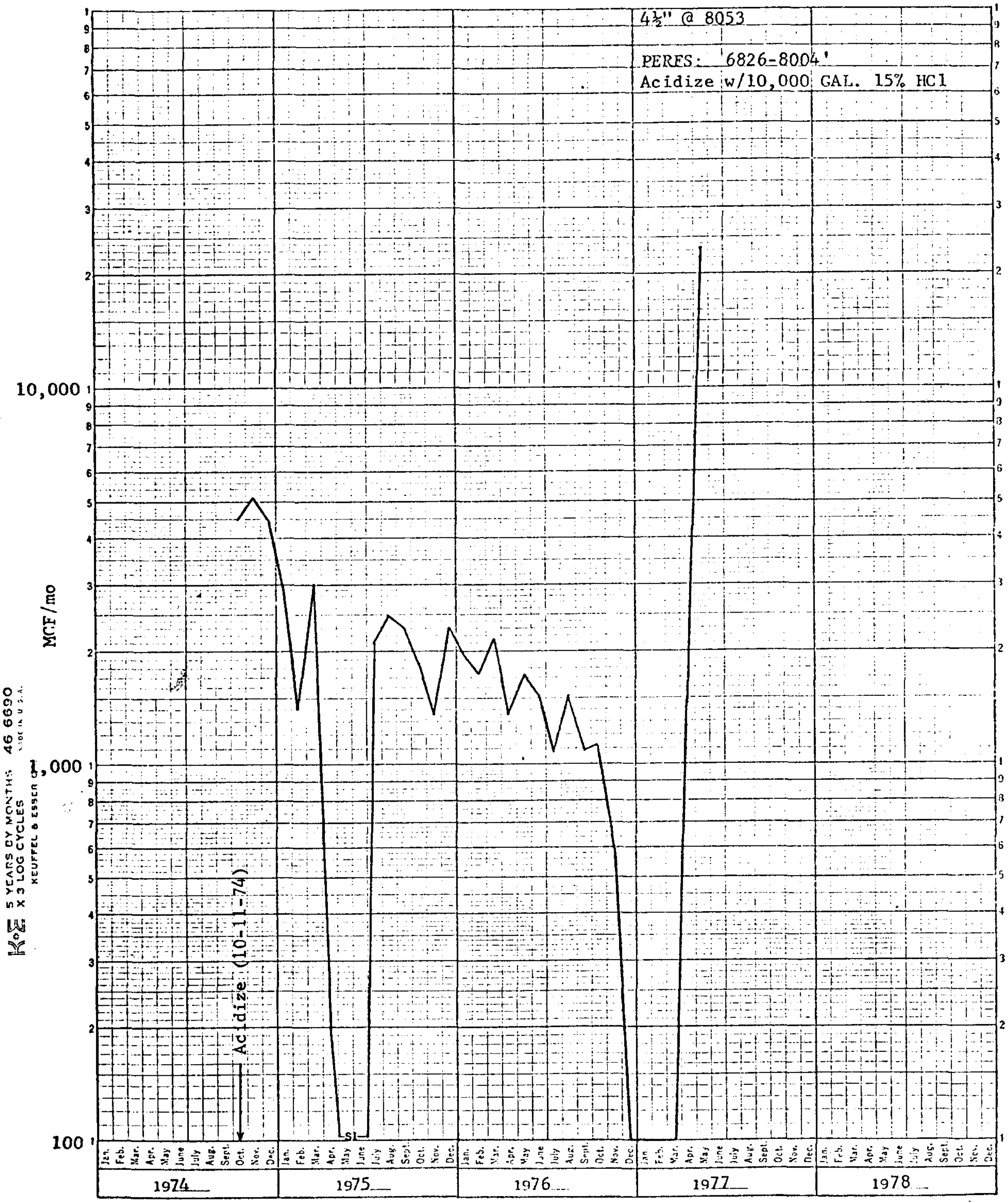


FIGURE 6

NATURAL BUTTES NO. 14



MASSIVE HYDRAULIC FRACTURING EXPERIMENT
NO. 1 HOME FEDERAL WELL, UINTAH COUNTY, UTAH

by

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ABSTRACT

Two massive hydraulic fracturing experiments were performed on two separate gas-bearing intervals of Mesaverde sandstones in the No. 1 Home Federal well located in Uintah County, Utah. KCl water was used as the frac fluid and the limited entry technique was used for injection.

The first experiment was carried out on an interval containing 112 ft. of net pay at a depth of 10,014 - 202. Pre-frac production capacity was estimated to be 60+ MCF/D. Post-frac production capacity was significantly less, presumably attributable to a limited lateral extent of inherent formation permeability.

The second experiment was carried out on an interval containing 85 ft. of net pay at a depth of 7,826 - 9,437 ft. Pre-frac production capacity of 33 MCF/D was increased by MHF to an initial 500 MCF/D and to a relatively stabilized 155 MCF/D within four months following the treatment.

Prepared for ERDA under Contract No. EY-76-C-08-0683. References, tables, and illustrations at end of paper.

I INTRODUCTION

Western Oil Shale Corporation and Texas American Oil Corporation performed two massive hydraulic fracturing experiments on the No. 1 Home Federal Well located in Sec 34, T10S, R19E, Uintah County, Utah. The first MHF was carried out on Oct. 1, 1976 and the second on Dec. 21, 1976. Both treatments were applied to low permeability, gas-bearing sands in the Mesaverde formation.

A. Well Description

The No. 1 Home Federal Well was spudded on December 11, 1975, was drilled with KCl water to total depth of 10,780 on January 13, 1976, and was cased to total depth on January 15, 1976.

Hole Specifications:

Conductor: 18" Dia., 60' depth
Intermediate: 11" Dia., 3032' depth
Final: 7 7/8" Dia., 10708' depth

Casing and Tubing Specifications:

Conductor Pipe: 13 3/8" OD, J-55, 48#/ft. set at 51' depth, cemented to bottom of cellar.
Intermediate Casing: 8 5/8" OD, J-44, 1129.75' of 32#/ft. and 1888.25 ft. of 24#/ft., set at 3017' depth, cemented to surface.
Production Casing: 5 1/2" OD, N-80, 23#/ft., set at depth of 10,780', cemented to 6900' depth.
Production Tubing: 2 3/8" OD, J-55 - 76 joints and N-80 - 245 joints, 4.5#/ft., set at 9,768 ft. depth.

Logs

Compensated Density
Contact Caliper Forzo
Sidewall Neutron
BHC Sonic with Caliper
Gamma Guard

B. Fracture Design Basis

The fracture design for both treatments was based primarily upon the finding that KCl water did not appear to damage the permeability of Mesaverde sandstone cores from another well in the Uinta Basin. Both treatments therefore utilized KCl water along with appropriate additives applied by the limited entry technique.

C. Reservoir Description

The two intervals treated were located between the depths 10,014-10,202 ft. (Interval #1/MHF#1) and between 7,826 - 9,437 ft. (Interval

#2/MHF#2). Individual zone depths, net pay thicknesses, average water saturations, and porosities based on log analysis are presented as follows for these two intervals:

INTERVAL #1 (MHF#1)

Zone Depth, ft.	Net Pay, ft.	Average Water Saturation, %	Average Porosity, %
10,014 - 038	22	33	12.7
10,044 - 062	18	40	12.3
10,088 - 100	12	42	9.7
10,136 - 148	10	34	11.0
10,142 - 202	50	43	11.0
	112 Total	41 Avg	11.8 Avg

INTERVAL #2 (MHF #2)

Zone Depth, ft.	Net Pay, ft.	Average Water Saturation, %	Average Porosity, %
7,826 - 29	3	53	8.5
7,852 - 81	27	51	8.5
7,974 - 80	6	40	8.5
8,042 - 46	4	35	8.5
9,225 - 37	12	51	8.0
9,308 - 14	6	40	7.0
9,410 - 37	27	40	9.5
	85 Total	45 Avg	8.5 Avg

II MHF #1 EXPERIMENT

MHF #1 consisted of 411,640 gallons of frac fluid and 600,000 pounds of sand. Injection rate varied between 19 and 46 BPM. Wellhead injection pressures varied between 6,400 and 7,000 psi.

A. Pre-frac Treatment

On March 31,1976 Welex perforated the target interval with 23 1/4"-diameter holes with Sidewinder jet charges between the depths of 10028 and 10200 feet. No gas showed at the surface after the perforating job was completed. Perforation depths were as follows:

10,028	10,091	10,137	10,167	10,179	10,192
10,032	10,093	10,140	10,171	10,182	10,196
10,058	10,096	10,143	10,174	10,185	10,200
10,062	10,098	10,163	10,176	10,188	

The perforations were broken down using acid, KCl water and ball sealers on April 4, 1976. Total fluid used in the breakdown was 380 barrels. Most of the breakdown fluids were recovered by April 13.

B. Pre-frac Production and Testing

Cumulative production into the wellbore prior to shut-in for pressure buildup monitoring is estimated to be 716 MCF. Volumes produced from the well are listed as follows:

DATE	VOLUME, MCF
Prior to 4/12	144
4/12	167
4/13	12.7
4/14	40
5/5	322.7
TOTAL	696.4

An additional volume of 19.5 MCF is estimated to have flowed into the wellbore but was not produced during the last 16 1/2 hours of the 24-hour production period. These volumes were measured or calculated utilizing wellhead and bottom hole pressure data, the volume of void inside the wellbore of 1308 cubic ft., and an average temperature inside the wellbore of 150° F.

Bottom hole pressures were measured with a 72-hour pressure bomb by Cable Engineering Company of Roosevelt, Utah prior to, during, and subsequent to the 24-hour production period commencing May 5, 1976. These bottom hole pressure data are presented in the Cable Engineering Company data sheets in Appendix A. The pressure data show that the stabilized pressure at a depth of 10,114 ft. was 6,631 psi just prior to the 24-hour production period. This pressure was reduced to 2,091 psi by flowing the well for approximately 7 1/2 hours. At 7 1/2 hours the flow rate was held at 40+ MCF/D with the bottom hole pressure rising at a rate of about 20 psi per hour. At 15 hours into the production period, the flow rate was stabilized at 40 MCF/D. At the end of the flow test (24 hours) the production rate was still 40 MCF/D while the bottom hole pressure was rising at a rate of 13.5 psi per hour. Flowing tubing pressure was 775 psig and flowing casing pressure, 350 psig. The bottom hole pressure at shut-in was 2,387 psig.

Final flow capacity is estimated to have been 62 MCF/D, considering the observed flow rate and the pressure buildup rate.

The well was shut in after removing the pressure bomb until August 26, at which time gas was produced on a 20/64" choke into the Mountain Fuel line located north of the well. Production was intermittent because of the well loading up with water.

Observed pressures and flow rates prior to September, 1976 were:

DATE	FTP, psig	FCP, psig	FLOW RATE, MCF/D
8/27	1375	490	40
8/28	1725	490	40
8/29	1925	490	40
8/30	2175	490	40
8/31	2340	425	40

A temperature survey was run on September 27. The results are depicted on Figure 1 along with the perforation locations. As indicated by the static log in this figure, slight cooling (indicating gas influx) appeared to have occured over zones 1, 2, 4 and 5. Zone 3 does not appear to exhibit any significant cooling at all.

C. MHF Treatment Description

Halliburton Services had all equipment and materials in place and ready to frac by September 28. There were twenty-one 500-barrel tanks of 2% KCl water, two blender trucks (only one truck was needed for the frac job; the additional truck was on standby only), ten pump trucks each capable of acheiving 1,000 hydraulic horsepower, three sand tanks with capacities of 2,560 cubic ft. each, two chemical trucks, a control van, and a number of ancillary pieces of equipment such as headers, valves and lines. Three flow lines were attached to the well, two connected to the casing and one connected to the tubing.

Halliburton started the massive frac with a KCl water prepad stage on September 29 at 1000 hrs. Maximum injection rate achieved was 12 BPM at 7,000 psig wellhead pressure (target rate was 42 BPM). The frac was stopped and 50 ball sealers were dropped, along with 3,000 gallons of acid in an attemt to increase the injection rate. The prepad stage was then restarted and a rate of 16 BPM was achieved. The prepad stage of 43,400 barrels was completed at approximately this injection rate.

On September 29, 2976 another temperature survey was run to determine appropriate locations for additional perforations. The results of this survey are presented in Figure 2 along with the original perforation locations.

Based upon the analysis of this temperature log and Halliburton calculations, 32 new 1/4" perforations were added to the target interval on September 30, 1976. The depths of the new perforations are as follows:

ZONE 1	10,027
	10,029
	10,030
	10,032
ZONE 2	10,059
	10,060
	10,061
ZONE 3	10,090
	10,092
	10,094
	10,095
	10,097
	10,098
ZONE 4	10,139
	10,141
	10,142
	10,144
	10,145
	10,146
ZONE 5	10,165
	10,169
	10,172
	10,175
	10,178
	10,180
	10,184
	10,187
	10,189
	10,194
	10,195
	10,197
	10,199

After perforating, Halliburton spotted 3,000 gallons of acid and dropped 75 ball sealers. The fracture treatment was then reinitiated with another prepad stage of KCl water at 1503 hrs. Maximum initial injection rate was 15 BPM at 7,000 psi. The frac was stopped after a few minutes and restarted at 1530 hrs. At this point an injection rate of 27 BPM at 6900 psi was achieved. The prepad stage was finished at 1628 hrs. and the wellhead was secured for the night.

The fracture treatment was recommenced at 1118 hours and was completed at 1542 hours on October 1, 1976. The following frac conditions prevailed:

Average Injection Pressure: 6850 psi

Average Injection Rate: 29 bbls/min.

Average Hydraulic Horse Power: 4,869

Maximum Injection Pressure: 7,000 psi

Maximum Injection Rate: 46 bbls/min.

The injection pressure, flow rate and sand concentration are plotted as a function of time in Figure 3. This is an idealized plot taken from the detailed log in the subcontractor's report.

Total volume of fluid injected prior to the October 1, 1976 operation was 96,920 gals. On October 1, the treatment was started with pad volume of 90,000 gals. followed by the stages listed below:

STAGE 1	10,000 gals. with 1 lbs/gal 40-60 sand
STAGE 2	35,000 gals. with 2 lbs/gal 40-60 sand
STAGE 3	40,000 gals. with 3 lbs/gal 40-60 sand
STAGE 4	30,000 gals. with 2 lbs/gal 20-40 sand
STAGE 5	60,000 gals. with 3 lbs/gal 20-40 sand
STAGE 6	40,000 gals. with 4 lbs/gal 20-40 sand

These six stages were followed by a 1,000-gal. Versagel spacer and 9,240 gal. displacement for a total volume injected of 315,340 gallons during the October 1, 1976 operation. By including the pre-pad and break down treatments on September 29 and 30, 1976 a total of 411,640 gallons were injected.

The materials used and their concentrations during the fracturing treatment are listed in Table 1.

D. Post-frac Production and Testing

Immediately following the fracturing treatment a temperature survey was run, the results of which are shown in Figure 4. The well was then opened on a 26/64" choke at 1225 hours with a wellhead pressure of 3400 psi. On October 2, the choke size was reduced to 20/64". Load water was recovered via a 20/64" choke until October 9 at which time a 26/64" choke was inserted. The cumulative load water recovery is shown as a function of time in Figure 5.

On October 7 at 1245 hours, the well was hooked up to the gas pipeline and gas was produced to sales. The well died at 2400 hours on this date. It was opened to the air and the pressure bled down to 0 in three minutes. It was shut in at 1400 hours on October 8. On October 9, NOWSCO pumped 93 MCF of nitrogen into the casing and the well started flowing again. The well was shut in on October 12 by the automatic shutdown valve. The well was opened to the air and a gas flow rate of 21 MCF/D was observed. On October 13 the well was shut in at 0800 hours. On October 21 through November 11 the well was shut in for pressure buildup. This pressure buildup is plotted in Figure 6.

Post-frac gas production prior to the pressure buildup is shown graphically in Figure 7. Also shown are the flowing tubing and casing pressures. As indicated in this figure, cumulative gas production was 325 MCF over a period of 5 1/2 days for an average of 59 MCF/D.

Shut-in bottom hole pressures were measured on November 1, 1976. The shut-in casing pressure as measured at the wellhead was 2775 psi just prior to running the down hole pressure bomb. Down hole pressures measured were as follows:

DEPTH, ft.	PRESSURE, psi
6400	3102
9500	4392
9700	4471
9900	4557
*10,114	4649

*Middle of perforations

The fluid level in the well was found to be 3,000 ft. during these measurements.

On November 11 the tubing was opened and the well flowed water to the pit. At 12:30 p.m. gas was produced into the pipeline at the rate of 393 MFC/D on a 12/64" choke, after unloading approximately 35 barrels of water. On November 12 the choke became plugged and approximately 250 barrels of water were unloaded. After unloading, gas was produced into the pipeline at the rate of 699 MCF/D on a 16/64" choke. On November 13 gas flow rate dropped to 129 MCF/D and after unloading ten barrels of water the rate increased to 550 MCF/D. On November 14 the well was shut-in and attempts were made thereafter to unload the water with nitrogen. On November 17 the well was producing at a rate of 731 MCF/D on a 16/64" choke. Thereafter the well died and only traces of gas were produced. The total volume of gas produced during November was only 60 MCF.

III MHF #2 EXPERIMENT

MHF #2 consisted of 247,500 gallons of frac fluid and 450,000 pounds of sand. Injection rate varied between 17 and 36 BPM. Wellhead injection pressure varied between 5,500 and 7,000 psi.

A. Pre-frac Treatment

The isolation of the first MHF zone was completed by pumping 12,000 pounds of sand into the wellbore. Top of the sand was found to be 9,922 ft. upon completion of the zone isolation.

The tubing was pulled to allow the remainder of the Mesaverde pay zones to be perforated with a Welex 3-1/2" casing gun. On December 2 the well casing was perforated with single .34" perforations at each of the following depths:

7768 ft.	7975 ft.	9227 ft.
7827 ft.	7979 ft.	9233 ft.
7855 ft.	8044 ft.	9311 ft.
7860 ft.	9045 ft.	9415 ft.
7869 ft.	9050 ft.	9420 ft.
7877 ft.	9223 ft.	9425 ft.
		9433 ft.

The top of the sand was found at a depth of 9872 ft. after perforating.

The well was killed with brine and a bridge plug was emplaced at a depth of 9460 ft. The tubing was then pulled back to a depth of 7750 ft. and the well was acidized with 2,500 gal. of 15% HCl containing a NE agent. 35 ball sealers were used and good ball action was observed. The well was opened to the pit after acidizing. It flowed back approximately 15 barrels and died. 34 barrels of 3% KCl water were then pumped down the tubing, and the bridge plug was retrieved.

B. Pre-frac Production and Testing

On December 5 a flow rate of approximately 200 MCF/D was observed. After a brief shut-in period for pressure build-up the tubing was run into the well along with 144 barrels of brine to kill it. The bottom of the tubing was set at a depth of 9359.75 ft. The hole was circulated with 200 barrels of 3% KCl water prior to shut-in.

The well was shut in from December 6 to December 10. On December 10 a trace of load water and gas were flowed and a bottom hole pressure bomb was run to a depth of 9430 ft. at 12:15 p.m. The tubing was left open to the pit overnight. A trace flow of gas was observed along with an estimated 50 barrels of water per day. The bottom hole pressure bomb was pulled on December 11. The data from these pressure measurements are presented in the Cable Inc. report in Appendix B. As indicated by these data, the average reservoir pressure is estimated to be 4,264 psig, and reservoir temperature 186° F.

After the bomb was pulled, nitrogen was injected to unload water from the tubing and casing. The well was then left open to the pit and flowed a trace of gas and more than 100 barrels of water.

On December 14 a 180 hr. pressure bomb was run into the well by Cable Inc. The bomb was on bottom at 6:35 p.m. During the first 41 hrs. and 45 min. of the pressure measurements, the well was open to the pit so as to unload the water prior to a gas flow test which was begun at 12:30 p.m. on December 16 (41 hrs. and 45 min. after the pressure bomb was on bottom). The flow test was conducted for 22 hrs. and 15 min., ending at 10:45 a.m. on December 17. Average flow rate was 33 MCF/D. Therafter the well was shut-in for pressure build-up. The bottom hole pressure data are presented in the Cable Inc. report in Appendix C.

C. MHF #2 Description

Halliburton conducted the massive hydraulic fracturing of the well on December 21. The job was begun at 10:15 a.m. and was completed at 1:42 p.m. The average injection pressure was 6500 psi; the average injection rate 35 barrels per minute; and the average hydraulic horse power used was 5,576. Total fluid volume used was 247,500 gal. This included a pad of 40,000 gal., a treatment of 200,000 gal. and displacement of 7,500 gal. The frac fluid was Halliburton's 'Versagel'. 50,000 lbs. of 40-60 sand and 450,000 lbs. 20-40 sand were used to prop the fracture. The frac fluid additives are listed in Table 2 and the frac pressures and injection rates are plotted in Figure 8.

D. Post-frac Production and Testing

The load water was flowed back beginning at 7:15 p.m. on December 21. Sand flowed back in sufficient quantities to erode holes in the flow line. The sand stopped flowing back at 5:00 a.m. on December 22.

On December 27 the well was hooked up to the treating unit and gas sales were commenced at a rate of 477 MCF/D. The production rates as a function of time from December 27, 1976 through June 30, 1977 are depicted in Figure 9. As indicated in this figure, the rate had essentially stabilized at about 155 MCF/D in April and remained at this average level throughout May and June.

Cumulative water production from the start of flowback throughout June, 1977 is shown in Figure 10. As indicated by this figure, the water production rate stabilized in March at about 20 BPD.

IV CONCLUSIONS AND RECOMMENDATIONS

Both MHF treatments clearly resulted in non-economic production rates. Because of the limited success achieved by MHF #2 on Interval #2, it is believed that the reason for the disappointing MHF #1 results was the inherent inadequacy of Interval #1 to release its gas; probably because of an extremely limited radial extent of permeability. Assuming this to be the case, it follows that KCl water is compatible with the Mesaverde sands at least to an extent, and therefore, may prove to be an acceptable, inexpensive frac fluid for this formation.

MHF #2 enabled Interval #2 production rate to increase from 33 MCF/D to an initial 500 MCF/D and to a somewhat stabilized 155 MCF/d at approximately 4 months following the frac.

It is recommended that MHF experimentation be continued with KCl frac fluid and limited entry injection in the Uinta Basin. Improved methods obviously need to be developed to 1) identify all sands amenable to successful MHF treatment in a given well and 2) identify those areas in a given basin that are most likely to contain sufficient thicknesses of sands amenable to successful treatment. It is recommended that developmental work on these improved methods be given at least as high a priority as is given to carrying out experimental MHF treatments.

TABLE 1. MATERIALS INJECTED - MHF #1

MATERIAL	AMOUNT	CONCENTRATION, Amt/1,000 gal.
Proppant 40-60 Sand	200,000 lbs.	1,000, 2,000, 3,000 lbs.
Proppant 20-40 Sand	400,000 lbs.	2,000, 3,000, 4,000 lbs.
Anti-Foaming Agent (NF-1)	365 gal.	1 gal.
Crosslinker (CL-11)	250 gal.	.6 gal.
Surfactant (Super-Flo)	365 gal.	1 gal.
Non Emulsifier (3N)	18 gal.	3 gal.
Fluid Loss Additive (WAC-11)	1,000 lbs.	50 lbs.
HCl Acid	1,000 lbs.	--
Gelling Agent (WG-2)	21,000 lbs.	60 lbs.
Friction Reducing Agent (FR-2)	250 lbs.	5 lbs.
Bactericide (Adocide)	185 gal.	.5 gal.
Breaker (AP)	250 lbs.	.1 - .25 lbs.
Breaker (GBW-3)	300 lbs.	.5 - 1.5 lbs.
KCl	77,000 lbs.	166 lbs.
Corrosion Inhibitor (HAI-50)	30 gal.	5 gal.

TABLE 2. HALLIBURTON FRAC FLUID ADDITIVES - MHF #2

ADDITIVE	TRADE NAME	CONCENTRATION UNITS SHOWN/ 1000 gal.	TOTAL USED
Non Foaming Agent	NF-1	1 lb.	248 lb.
Surfactant	TRI-5	1 lb.	248 lb.
Crosslinker	CL-11	0.5 gal.	121 gal.
Gelling Agent	WG-12	50 lb	124,000 lb.
Friction Reducer	FR-20	3 lb.	25 lb.
Breaker	AP-GBW-3	.25 lb, .5-1 lb.	61 lb., 86 lb.
Bactericide	Adocide	.5 gal	124 gal.
KCl		250 lb. (3%)	650 SKS

Date of Survey May 4, 7, 1976

BH Temp. 173 °F at 10,114 ft.

4:00 PM 4-14 76

Well Shut In 9:00 A M. 5-6 1976

Bomb On Bottom 6:13 PM. 5-4 1976

BOMB NO. 32496 CALIB NO. 5-1-76

72 HRS. = 5 INCHES

BUILDUP					
PT. NO	PRES DEF.	PRES (PSIG)	TIME	TBG PRES	CSG PRES
1	1.233	6631	482 hours 13 Min		
2	"	"	483 "		
3	"	"	490 "		
4	"	"	497 "		
5	1.233	6631	0		
6	0.822	4439	30 Min.		
7	0.824	4444	1 Hour		
8	0.820	4422	2 "		
9	0.777	4193	3 "		
10	0.745	4021	4 "		
11	0.747	4032	5 "		
12	0.749	4043	6 "		
13	0.379	2102	7 "		
14	0.386	2091	8 "		
15	0.394	2134	10 "		
16	0.401	2172	12 "		
17	0.412	2231	15 "		
18	0.431	2333	20 "		
19	0.441	2387	24 "		

Well shut in 4:00 P 4-14-76

Well open for flow 8/64 Choke

BUILDUP					
PT NO	PRES DEF	PRES (PSIG)	TIME	TBG PRES	CSG PRES
20	0.441	2387	0		
21	0.446	2414	30 Min.		
22	0.452	2446	1 Hour		
23	0.462	2500	2 "		
24	0.472	2554	3 "		
25	0.482	2608	4 "		
26	0.492	2661	5 "		
27	0.501	2710	6 "		
28	0.511	2763	7 "		
29	0.520	2812	8 "		
30	0.537	2903	10 "		
31	0.554	2995	12 "		
32	0.579	3129	15 "		
33	0.617	3333	20 "		
34	0.686	3704	30 "		
35	0.704	3801	33 "		

Shut in for BU

APPENDIX A CABLE ENGINEERING BHP DATA - PRE MHF #1

Date of Survey ~~Dec. 10, 11, 1976~~

BH Temp. 186 °F at 9430 ft.

Well Shut In ____ M. ____ 19__

Bomb On Bottom 12:15 P. M. 12-10 1976

BOMB NO. 3790 CALIB NO. 12-1-76

72 HRS. = 5 INCHES

~~XXXXXXX~~ DRAWDOWN					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
1	1.393	4264	0		
2	1.389	4252	30 Min		
3	1.387	4245	1 Hour		
4	1.384	4236	2 "		
5	1.381	4227	3 "		
6	1.379	4221	4 "		
7	1.377	4215	5 "		
8	1.376	4212	6 "		
9	1.375	4209	7 "		
10	1.374	4206	8 "		
11	1.374	4206	10 "		
12	1.373	4202	12 "		
13	1.373	4202	14 "		
14	1.376	4212	16 "		
15	1.381	4227	20 "		
16	1.378	4218	25 " 15 Min.		

APPENDIX B CABLE ENGINEERING BHP DATA FOR DEFINITION OF RESERVOIR PRESSURE - INTERVAL #2

Date of Survey Dec. 14, 20, 1976

BH Temp. 186 °F at 9430 ft.

Approx.
Well Shut In 12:20 P. M. 12-16 1976

Bomb On Bottom 6:35 P. M. 12-14 1976

BOMB NO. 3789 CALIB NO. 12-1-76

120 HRS. = 5 INCHES

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
1	0.686	2101	0		
2	0.697	2135	30 Min		
3	0.711	2177	1 Hour		
4	0.728	2229	2 "		
5	0.760	2327	3 "		
6	0.788	2413	4 "		
7	0.813	2489	5 "		
8	0.836	2560	6 "		
9	0.833	2550	7 "		
10	0.854	2615	8 "		
11	0.882	2700	10 "		
12	0.891	2728	12 "		
13	0.911	2789	15 "		
14	0.943	2887	20 "		
15	0.967	2960	25 "		
16	0.966	2957	30 "		
17	0.946	2896	35 "		
18	0.646	1979	40 "		
19	0.362	1110	41 " 45 Min.		

FORM 5-84

Well open for flow

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
20	0.362	1110	0		
21	0.382	1171	30 Min		
22	0.417	1278	1 Hour		
23	0.485	1486	2 "		
24	0.546	1673	3 "		
25	0.591	1810	4 "		
26	0.634	1942	5 "		
27	0.672	2058	6 "		
28	0.704	2156	7 "		
29	0.738	2260	8 "		
30	0.785	2404	10 "		
31	0.819	2508	12 "		
32	0.873	2673	15 "		
33	0.926	2835	20 "		
34	1.024	3135	30 "		
35	1.071	3278	40 "		
36	1.101	3370	50 "		
37	1.123	3437	60 "		
38	1.141	3492	70 "		
39	1.162	3557	80 "		
40	1.194	3654	95 " 10 Mn.		

Well shut in for BU

APPENDIX C CABLE ENGINEERING BHP DATA TAKEN FOLLOWING PRE-FRAC FLOW TEST - INTERVAL #2

FIGURE 1. STATIC AND DIFFERENTIAL TEMPERATURE SURVEYS - 9/27/76
INTERVAL #1

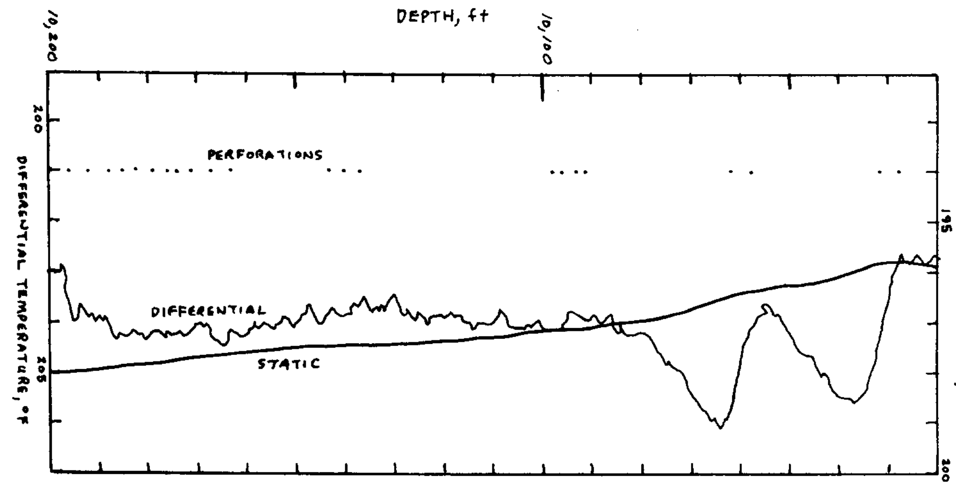
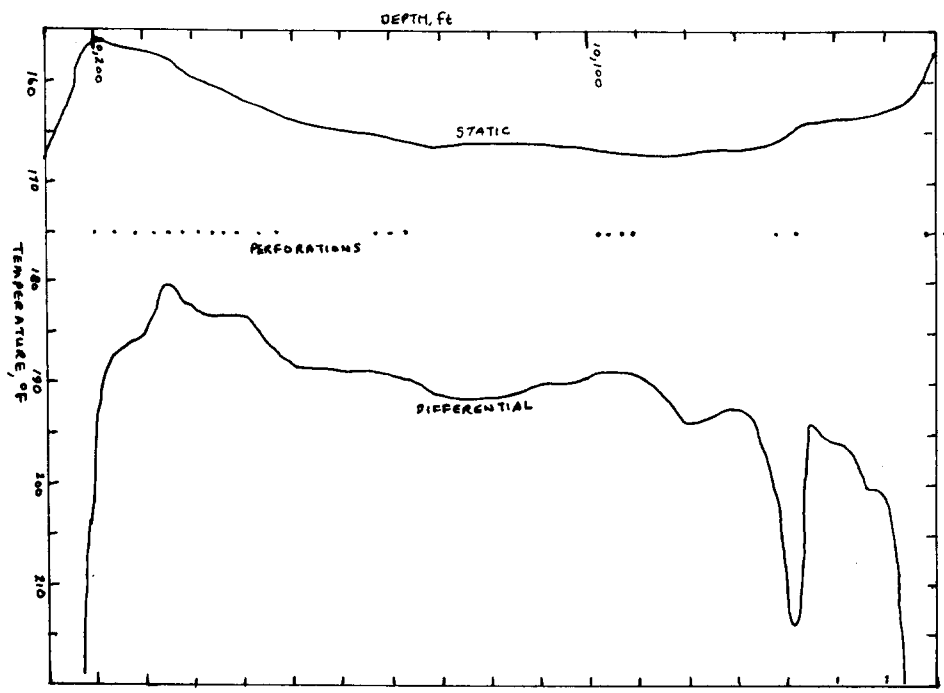


FIGURE 2. TEMPERATURE SURVEYS, 9/29/76 - INTERVAL # 1



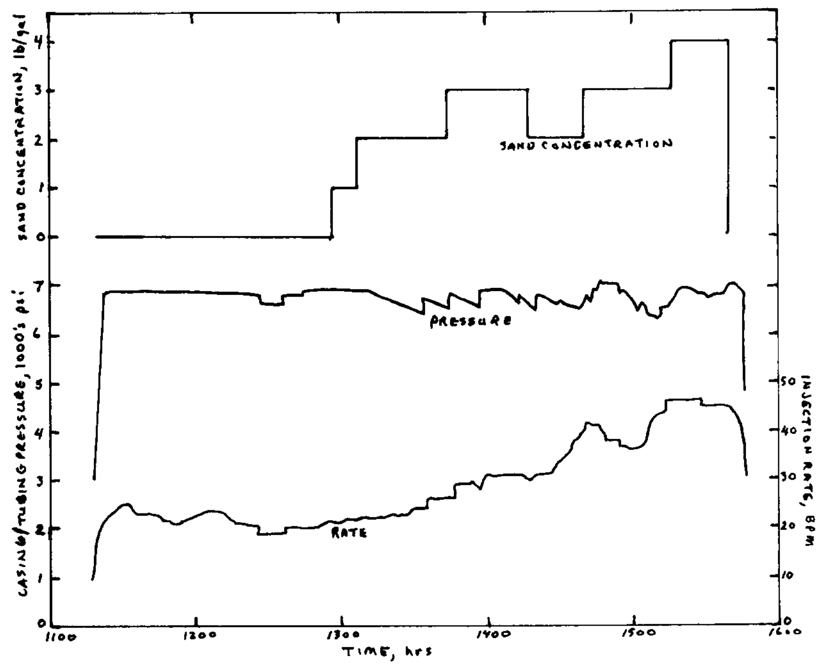


FIGURE 3. INJECTION PRESSURES, RATES, AND SAND CONCENTRATIONS
OCT. 1, 1976 - MHF #1

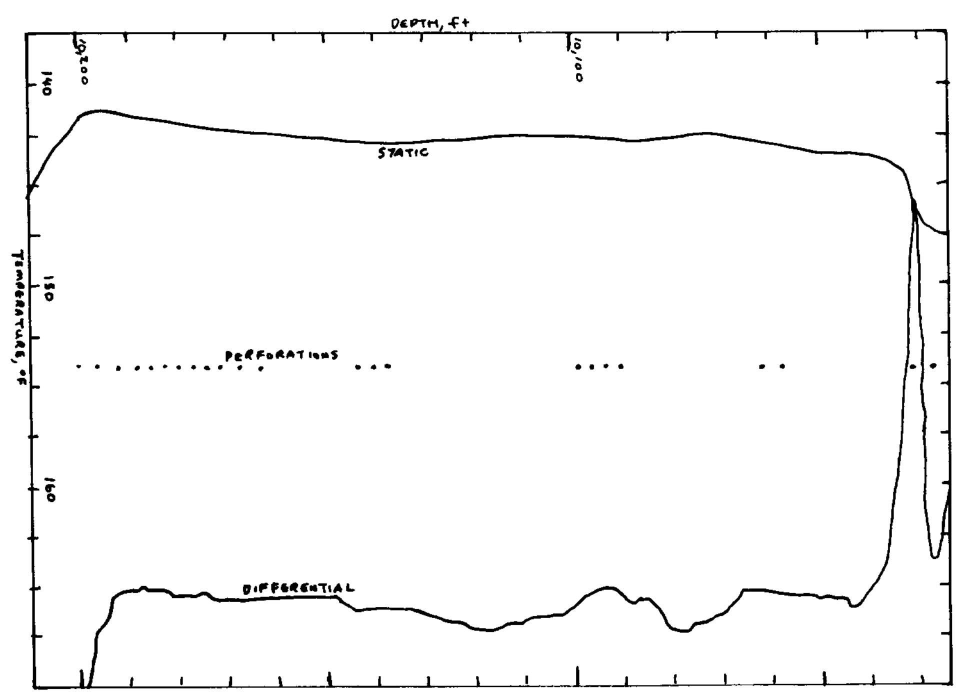


FIGURE 4. TEMPERATURE SURVEY - 10/1/76, POST MHF #1

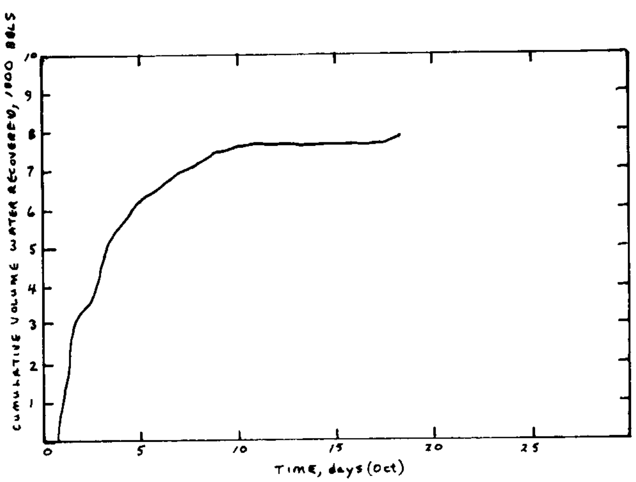


FIGURE 5. CUMULATIVE VOLUME OF LOADWATER RECOVERED VERSUS TIME - MHF #1

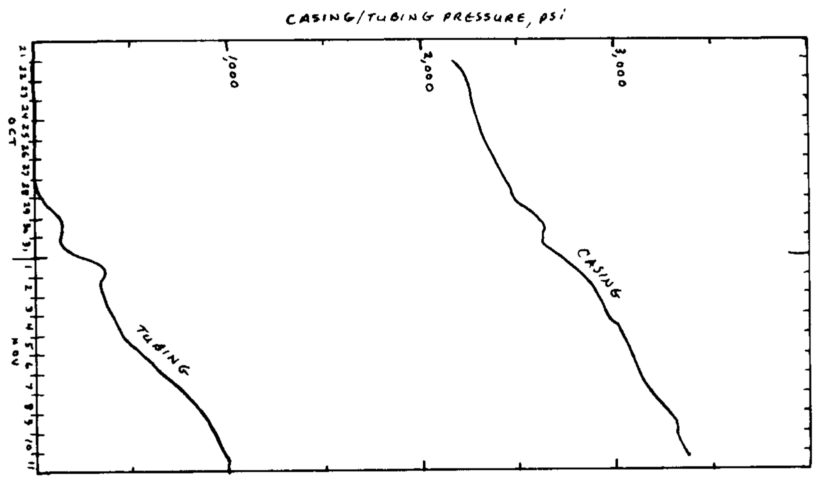


FIGURE 6 WELLHEAD PRESSURE BUILDUP FOLLOWING POST MHF #1 FLOW TESTING

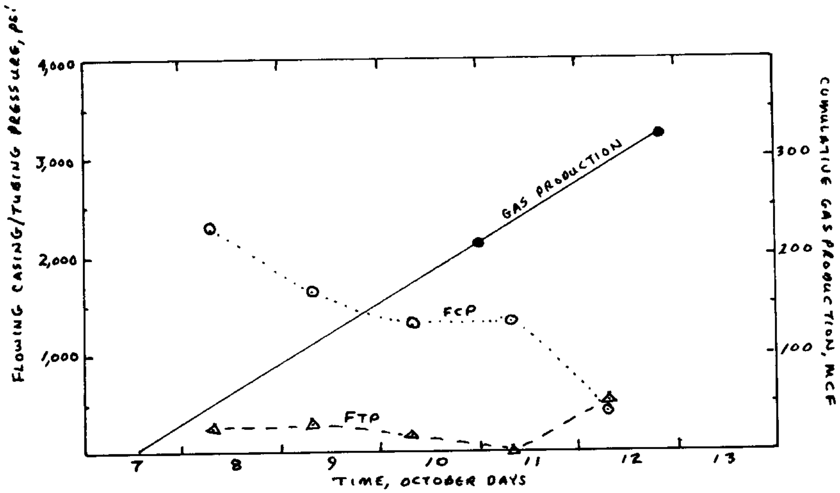


FIGURE 7. POST MHF #1 GAS PRODUCTION AND ASSOCIATED WELLHEAD PRESSURES

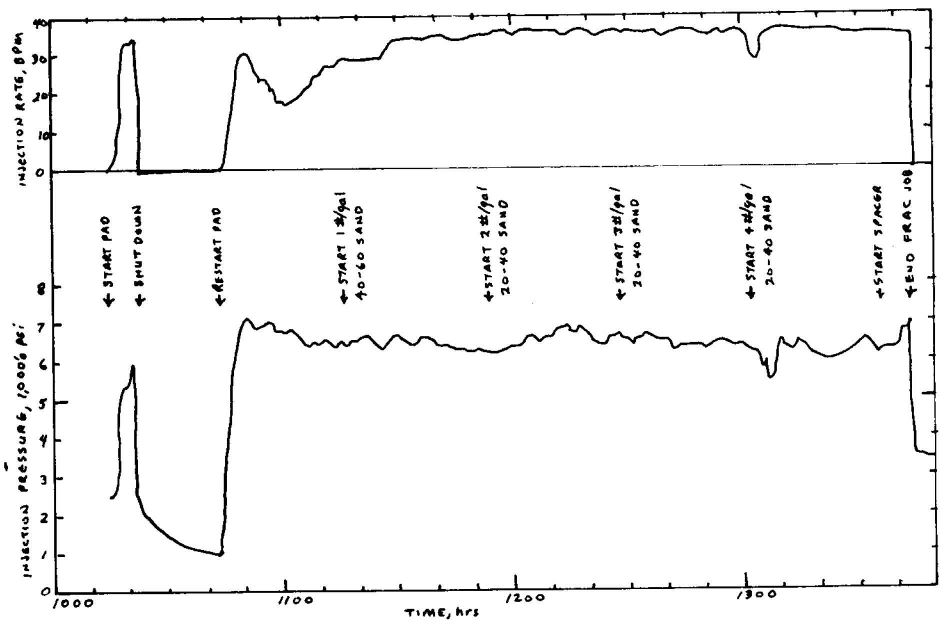


FIGURE 8. INJECTION PRESSURES AND RATES - MHF #2

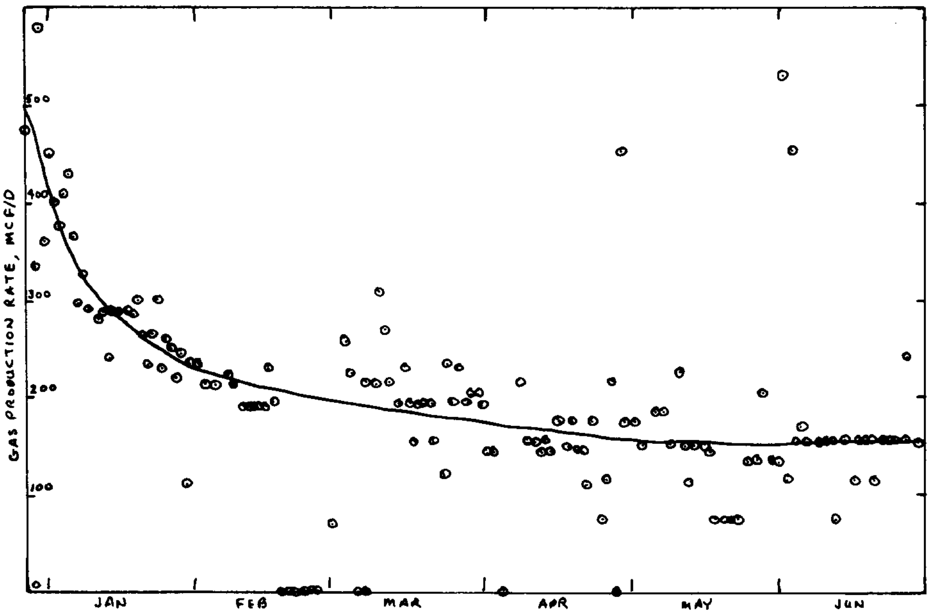


FIGURE 9. GAS PRODUCTION RATE VS TIME FOLLOWING MHF #2

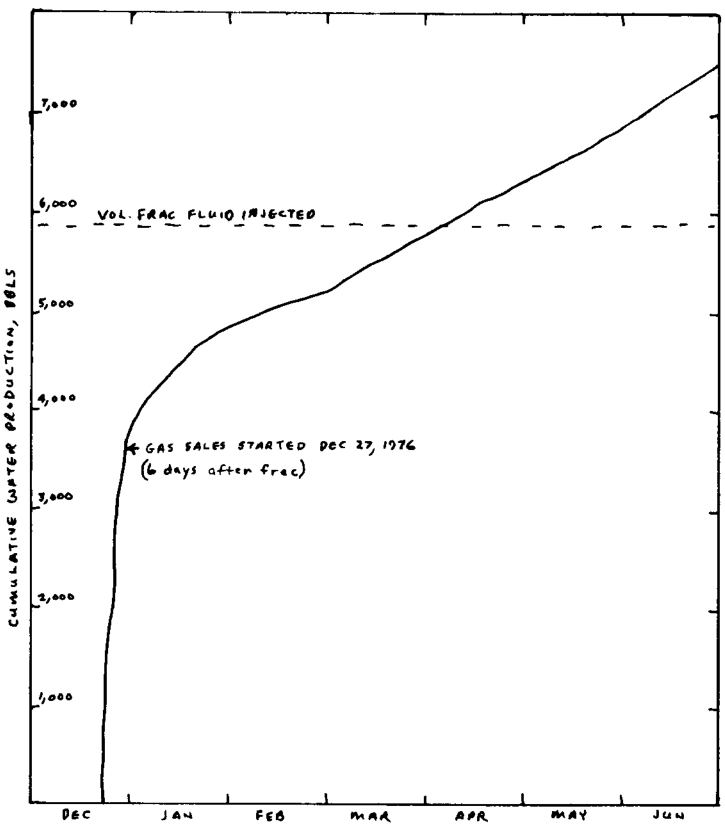


FIGURE 10. CUMULATIVE WATER PRODUCTION FOLLOWING MHF #2 VS TIME

MESAVERDE
HYDRAULIC FRACTURE STIMULATION
NORTHERN PICEANCE BASIN - PROGRESS REPORT

by

Robert E. Chancellor
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ABSTRACT

Information gained from massive stimulation projects in the northern Piceance basin was used to design a massive hydraulic fracture for a 130 foot thick Mesaverde Group interval in a nearby well. Pre-frac log interpretations indicated individual sandstone units in the zone to be gas productive with variable reservoir characteristics. It flowed 55 Mcfpd after a pre-frac breakdown of 16 perforations. Seven thousand barrels of jelled KCl water and 775,000 lb of sand were successfully injected at the rate of 37 barrels per minute. With 70 percent fluid recovery after 12 post-frac days, the flow rate was 800 Mcfpd. After one month, it dropped to 200 Mcfpd and stabilized at 130 Mcfpd plus an average of 3 barrels of high gravity oil and 3 barrels of water after four months on 1/4" choke at 60 pounds tubing pressure. These results are similar to two previous KCl based fracs performed in the well.

The KCl approach to drilling and completing Mesaverde wells in this area appears to offer economically successful stimulation ratios.

Prepared for ERDA under Contract No. EY-76-C-08-0677.

Introduction

The massive hydraulic stimulation of a 130 ft sandstone-shale interval in Mesaverde Group rocks of the northern Piceance basin was financed by a matching funds contract with the U. S. Energy Research and Development Administration at an approximate cost of $260,000.

Figure 1 illustrates the regional position in northwest Colorado of two government-industry project wells which were drilled and completed with the purpose of contributing to the technology of accelerating deliverabilities of natural gas from low permeability sandstone reservoirs in the Rocky Mountains. Final reports on these projects have not been published; however, the work is essentially completed. Information gained from the projects and from industry efforts in contiguous basins was influential in formulating the design and execution procedures for the current stimulation attempt.

The well involved was drilled by Rio Blanco Natural Gas Company (#498-4-1 Government) about five miles south of the previous government-industry projects (see figure 2) to correlative depths in the Williams Fork Member of the Mesaverde Formation.

Geologic Summary

Figure 3 is a diagrammatic cross section from Grand Junction to Craig, Colorado, showing the stratigraphic position of the rocks which were stimulated. The interpretation is by Mr. G. G. Loucks. The discontinuity of an extensive flood plain sequence comprises a regional permeability barrier to natural gas generated in contemporaneous swamp deposits. The zone which was stimulated is thought to be part of the nearshore facies of a brief but extensive invasion of the Lewis sea across the area.

As seen on figure 4, the interval is about 1500 ft structurally higher than correlative zones in the government-industry wells.

Figure 5 is a composite of pertinent data from the interval of interest. Ninety-five ft of sandstone is present. Sandstone Units 2, 3, 4, 7, 8 and 9 are medium to coarse grained.

Fracture Treatment

After perforating with 16 shots (black arrows), natural gas production was 6 Mcfpd. The perforations were subjected to a 111 barrel breakdown using 3% KCl, nitrogen, and ball sealers. Post breakdown flow was about 55 Mcfpd of 1142 B.t.u. gas. Calculations of reservoir capacity (Kh) indicated the interval contains about 1.0 millidarcy foot.

The volumes of fluid and sand for the frac were determined by computer calculations of fracture geometry. A total of 276,000 gallons of fluid (YF4PSD) was designed for the treatment, of which 12,000 gallons were to be used as pad. The remaining fluid carried a total of 775,000 lb of sand of the following size:

225,000 lbs	100 Mesh (FLA 110)
434,000 lbs	20-40 Mesh
116,000 lbs	10-20 Mesh

The fracturing fluid consisted of 40 lb of a refined gel per 1000 gallons of water. The gel was crosslinked to enhance fracturing fluid properties such as cleanup, stability, and the ability to transport large volumes of sand within the fracture. The gelling agent selected (PSD) hydrates at a lower temperature than guar, eliminating the necessity to maintain the water temperature at 70° F. PSD is cleaner than guar; i.e., it contains approximately 2% solids as opposed to 10% in the guar.

A very low surface tension additive, along with another surfactant that has clay stabilizing properties, was employed in the fracturing fluid.

The water used to prepare the frac fluid was tested several times, including prior to and after the on-site storage tanks were filled. Storage silos and sand quality were checked prior to the fracturing operations. A tailored breaker schedule was selected to provide for a total break in four hours from the time pumping started. This would allow for a short shut-in time with flowback started immediately after temperature surveys.

The calculated injection required was 37 BPM. This rate would provide approximately 650 psi differential pressure across the perforations. The spacer technique was designed into the treatment to insure maximum sand penetration. FLA 100 was used to inhibit fluid loss in any natural fractures encountered and to promote deeper penetration of the induced fractures.

Actual pumping for the massive fracturing started at 10:00 a.m. on October 22, 1976. A total of 7,617 barrels was pumped, including sand volume and flush. Injection rate was 37 BPM at 1,200 to 1,800 psi, with the rate being reduced at the end of the treatment. The job was performed as scheduled.

Post-frac cleanup proceeded quite satisfactorily (see figure 6). In brief, 30% of the fluid flowed back in the first 36 hours, after which the well died. Following eight days of swabbing and a total fluid recovery of 46%, the zone began continuous flow. Within an additional three days, total fluid recovery was 70%. Gas flow then increased from gas-cut water to 800 Mcfpd. Within 22 days the gas flow declined to the 200 Mcfpd range, with average fluid production being 3 barrels of water and 3 barrels of oil per day.

This production rate stabilized at 130 Mcfpd after three months of production.

Analysis of Characteristics

The ten sandstone units (figure 5) and their characteristics as indicated by log interpretation are as follows:

Unit No.	Sand Thickness feet	Sand %	Degree of Cementation	Drlg. Break	Gas Show	Fracture Gradient	Post Bkdn Flow	Post Frac Temp
1	10	90	Tight	Fair	Good	Good Top & bottom	zero	140
2	16	100	Friable	Good	Fair	Good Middle	14.4	-140
3	10	95	Friable	Fair	Fair	Poor	zero	-140
4	12	90	Tight	?	Fair	Good Top	9.7	140
5	8	75	Tight	Fair	Good	Fair	zero	140
6	6	50	?	Poor	Poor	Poor	8.4	-140
7	9	95	Friable	Fair	Good	Fair Top	19.1	-140

(continued)

Analysis of Characteristics - continued

Unit No.	Sand Thickness feet	Sand %	Degree of Cementation	Drlg. Break	Gas Show	Fracture Gradient	Post Bkdn Flow	Post Frac Temp
8	6	100	Friable	Poor	Poor	Good	16.8	+140
9	8	80	Friable	Good	Good	Poor	16.0	-140
10	10	70	Tight	Fair	Good	Good Top	15.6	+140

Before frac, logs indicated Units 1, 3 and 5 were not contributing to the flow rate. The frac effected communication with these units. Penetration was best into Unit 9, moderate into Units 2, 3, 5, 6, 7, 9 and 10, and least into Units 1, 4 and 8.

Pre-frac Indications of Receptivity to Penetration:

Unit 2: Positive in all characteristics.

Unit 3: Positive except for fracture gradient and post breakdown flow.

Unit 5: Positive except for post breakdown flow.

Unit 6: Negative in all characteristics except post breakdown flow and temperature logs.

Unit 7: Positive except for fracture gradient.

Unit 9: Positive except for overall sand quality.

Log Indications for Poorest Penetration:

Unit 1: Positive except for firmness and poor frac gradient in the middle.

Unit 4: Positive except for firmness and poor frac gradient in the middle.

Unit 8: Positive except for comparatively poor drilling break

Frac Result Summary

Units 1, 3, and 5 were not contributing to post breakdown flow. The frac probably established best communication with Unit 3 because of receptive sand quality.

Units 2, 3, 4, and 5 probably comprise one sandstone body 68 feet in thickness. The frac probably made its main penetration into Units 2 and 3, because of receptive sand quality.

Unit 6 may be a separate 24 foot unit of fractured or laminated sandy siltstone into which the frac penetrated.

Units 7, 8, 9 and 10 probably comprise one sandstone body 42 feet in thickness. The main frac penetration was into Unit 9, because of its receptive sand quality.

No combination of prefrac characteristics supplied by the methods used appears to furnish information indicative of specific sandstone unit receptiveness to frac stimulation in the Phase I Zone.

Conclusions

1. Sandstone units, which are the most friable and had the fastest drilling times, were those most receptive to fracture stimulation.

2. Gas shows in the drilling fluids or drill cuttings are not dependable indicators of the potential productivity of any particular sandstone unit.

3. In the absence of a consistent method for choosing those frac candidates most receptive to hydraulic fracturing, a sufficient number of sandstone units should be selected for treatment to

maximize the probability of successful averaging of individual stimulation ratios.

Comments on Economics

The #498-4-1 Govt. is the first well in the general area to be drilled using exclusively a KCl mud program and KCl frac fluids. The KCl system appears to result in an overall reduction of the degree of swelling of clay minerals. Older wells in the area completed in correlative zones required pumping equipment to bring the produced fluids to the surface in order to effect sustained gas flow. Prior to the MHF in #498-4-1 two fracs were performed immediately downhole in approximate 100 ft intervals. These stimulations resulted in a comingled flow rate of 250 Mcfpd. All three zones demonstrate an ability to sustain continuous flow rates sufficient to prevent fluid loading of the tubing and casing--eliminating the need for pumping equipment.

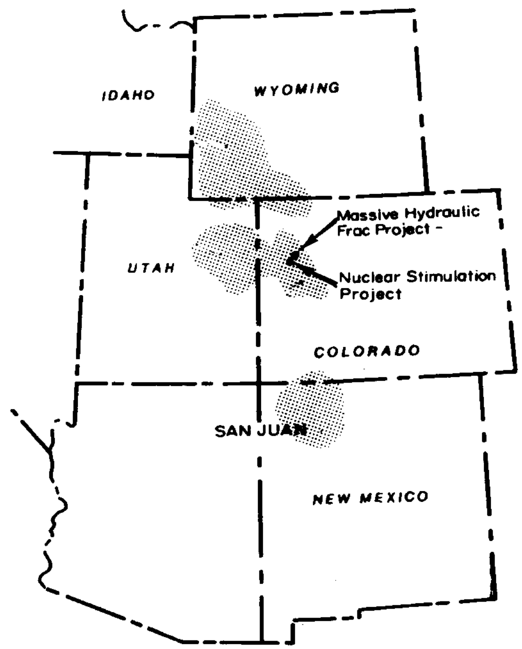
As seen on figure 3, the rocks treated thus far are vertically positioned in the middle of a 1500 ft thick sequence which is interpreted to be a stratigraphic gas trap. No appreciable volume of water has been recovered west of Piceance Creek field from this sequence in wells on figure 4 whose structural positions are between +1642 and -1375. The potential for a sizable development program exists. The fracs performed in #498-4-1 have effected about one-quarter of the zones of interest. If the present stimulation ratios can be maintained in treatment of the balance of the sequence a deliverability exceeding 1 million cfgpd will result.

As the art of fracture stimulation improves, and as the ability to select target sequences whose stratigraphic histories assure hydrocarbon generation and reservoir presence under trapping conditions increases, many cost savings will be possible.

Inherently, costs of drilling and completion in this tight gas reservoir will remain comparatively high. The referenced final report for the MHF includes an economic analysis of all work performed in #498-4-1 to date. It projects a six-year payout period for the $800,000 invested to date. Dependable calculation of payout time awaits federal action on gas pricing.

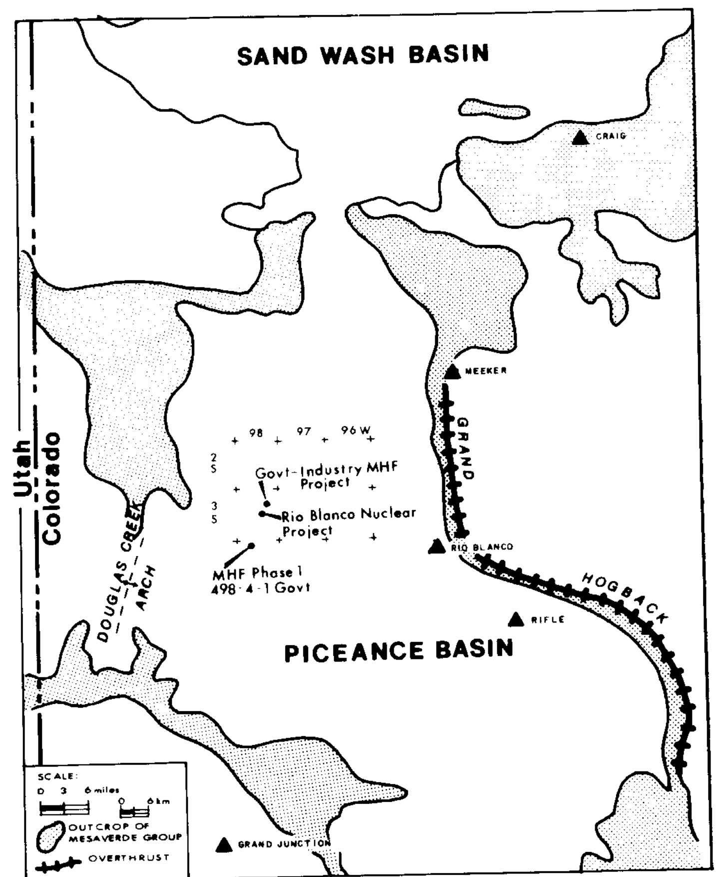
The timing of full scale development of this reserve will be keyed to realistic long term pricing regulations which recognize the economics involved.

Reference: Massive Hydraulic Fracturing Well Federal No. 498-4-1 Rio Blanco County, Colorado, Final Report, H. K. van Poollen, A. A. Ishteiwy, R. E. Chancellor, February, 1977. Prepared for the U. S. Energy Research and Development Administration, Nevada Operations Office, Under Contract No. EY-76-C-08-0677.



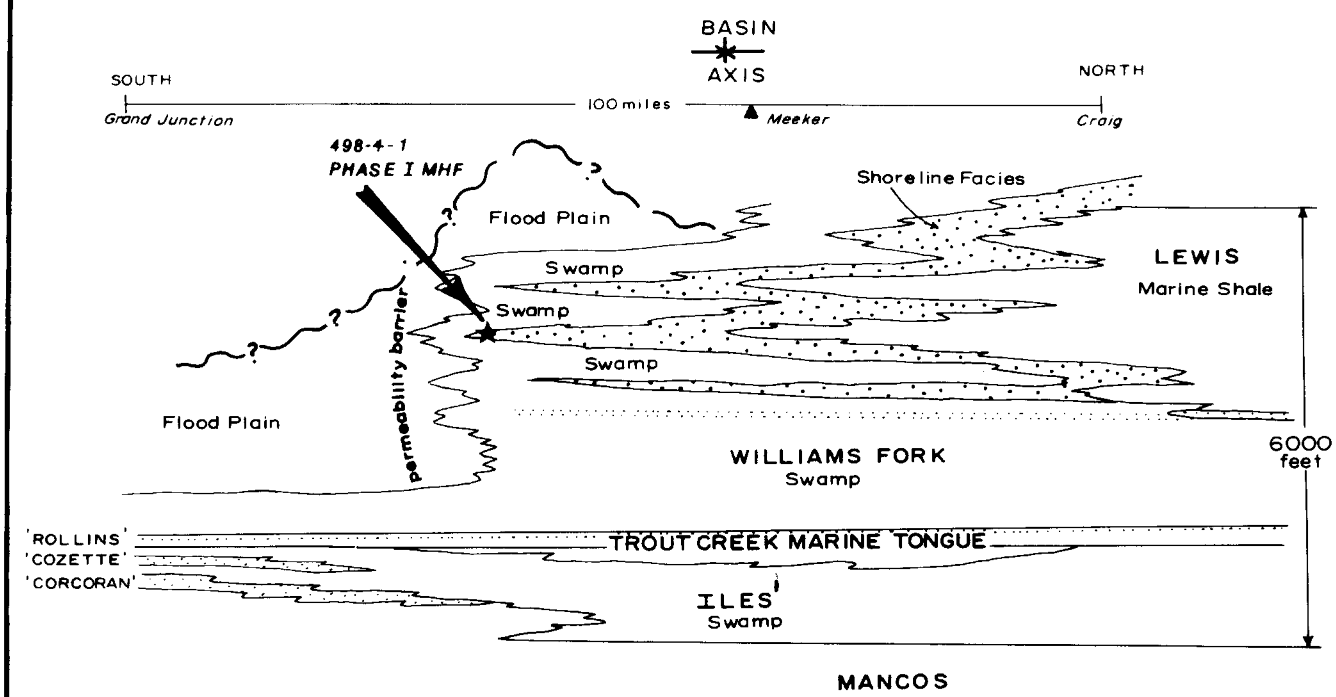
LOCATION OF GOVERNMENT-INDUSTRY PROJECTS FOR STIMULATING TIGHT GAS RESERVOIRS IN THE NORTHERN PICEANCE BASIN.

FIGURE I



PICEANCE BASIN - NW COLORADO
LOCATION OF MHF PROJECTS

FIGURE 2



DIAGRAMATIC NORTH-SOUTH CROSS SECTION FROM CRAIG TO GRAND JUNCTION SHOWING STRATIGRAPHIC POSITION OF 498-4-1 PHASE I, MHF

(after G.G. Loucks)

FIGURE 3

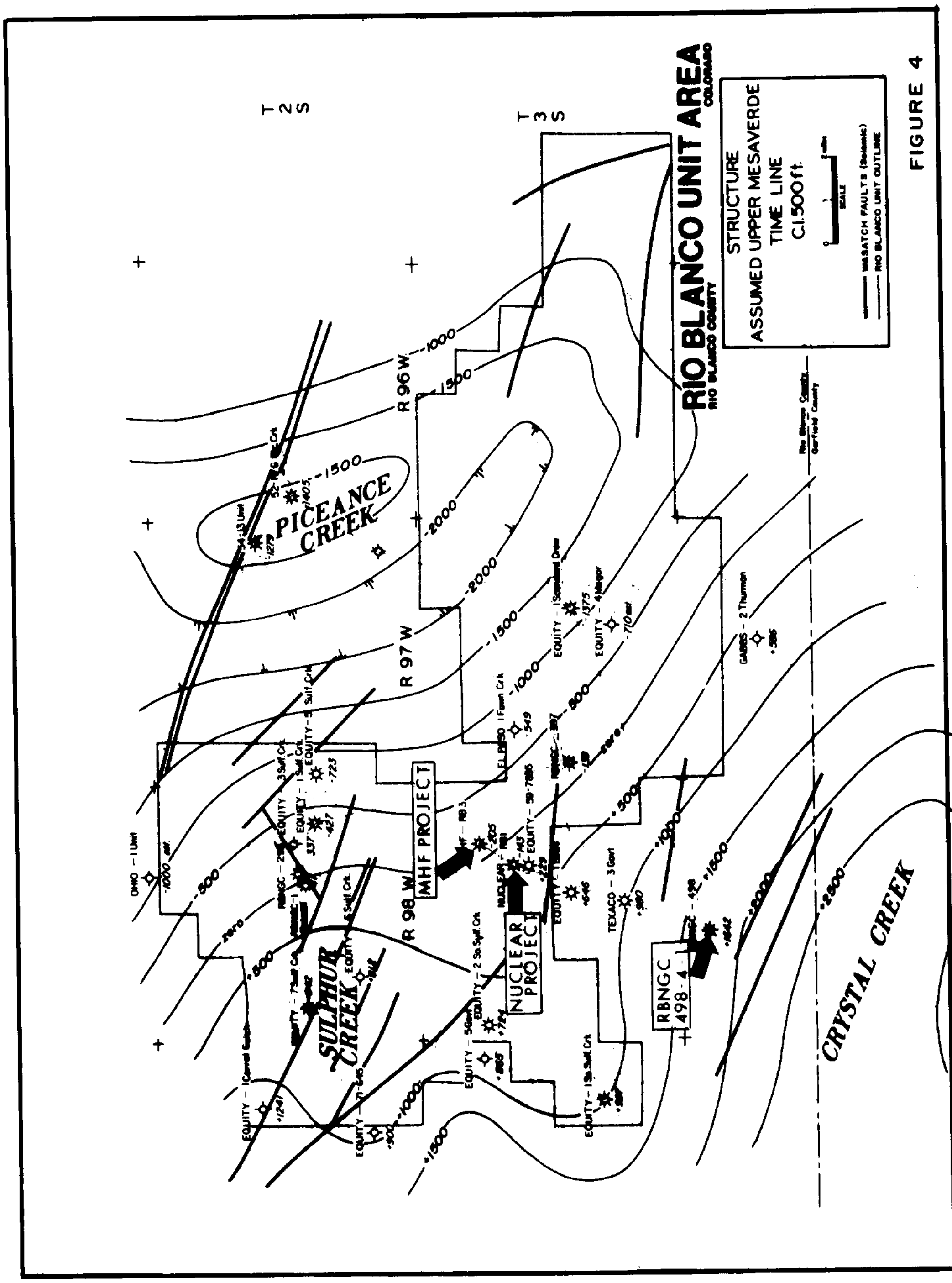

RIO BLANCO UNIT AREA
COLORADO
RIO BLANCO COUNTY
STRUCTURE
ASSUMED UPPER MESAVERDE
TIME LINE
C.I. 500 ft.
WASATCH FAULTS (Seismic)
RIO BLANCO UNIT OUTLINE
PICEANCE CREEK
SULPHUR CREEK
CRYSTAL CREEK
MHF PROJECT
NUCLEAR PROJECT
RBNGC
498-4
R 96 W
R 97 W
R 98 W
T
2
S
T
3
S
FIGURE 4

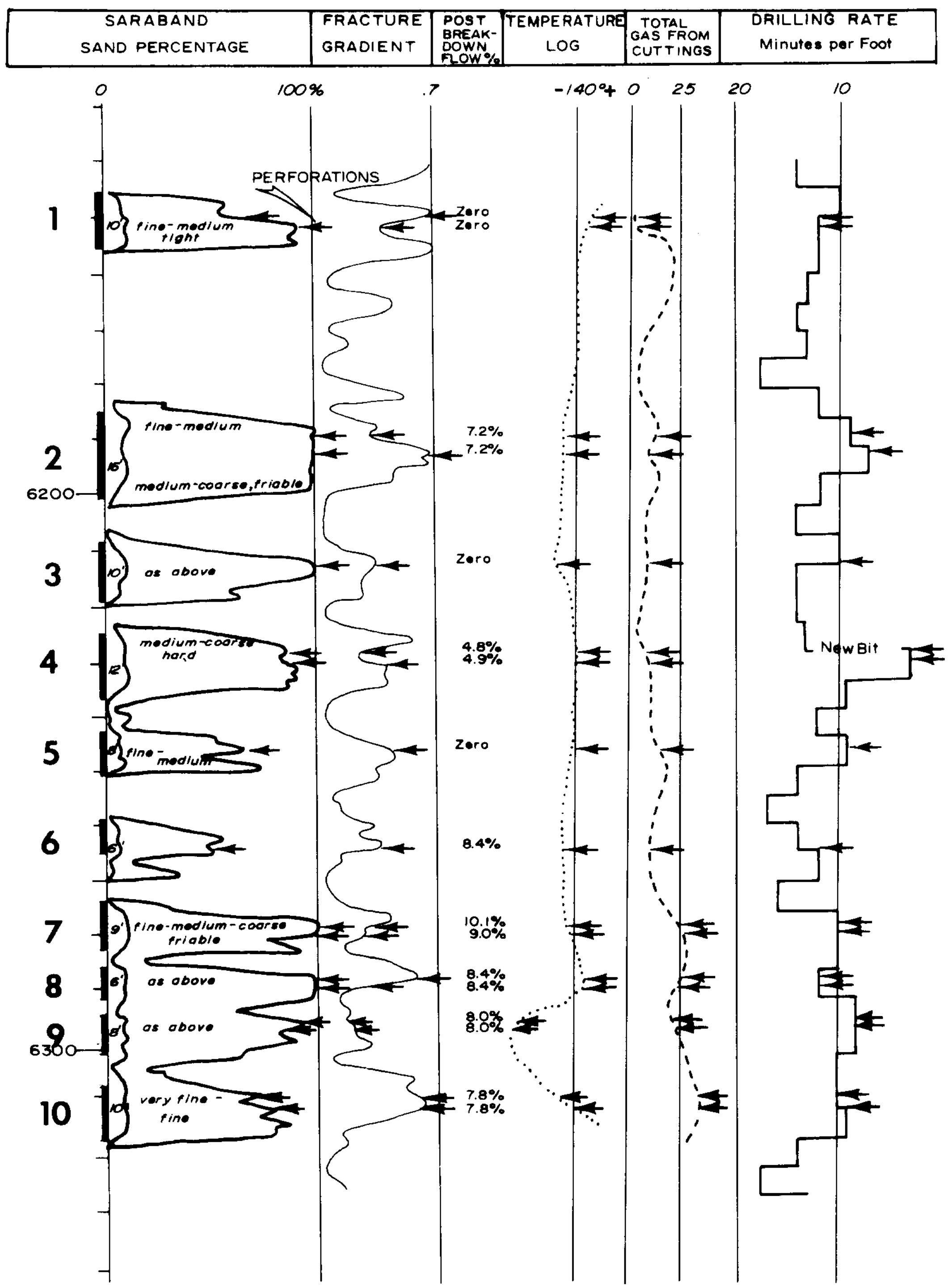
FIGURE 5

RIO BLANCO NATURAL GAS CO. - ERDA MHF 498-4-1

CONTRACT NO. EY-76-C-08-0677

PHASE I

10 SANDSTONE UNITS 95' TOTAL



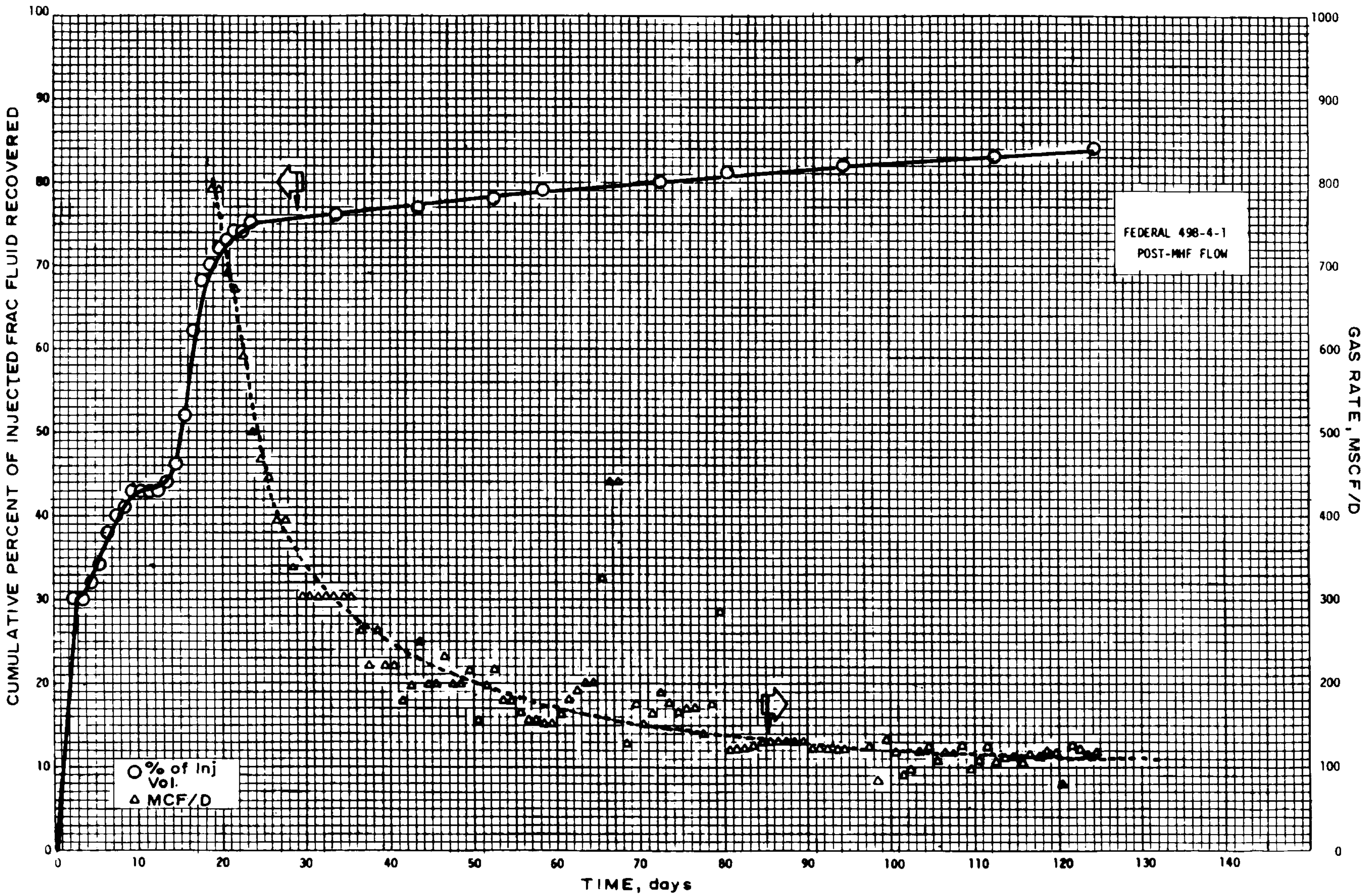

CUMULATIVE PERCENT OF INJECTED FRAC FLUID RECOVERED
GAS RATE, MSCF/D
TIME, days
FEDERAL 498-4-1
POST-MHF FLOW
○ % of Inj Vol.
△ MCF/D
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
100
200
300
400
500
600
700
800
900
1000

FIGURE 6

GAS STIMULATION STUDIES AT LASL

by

W. J. Carter, B. W. Olinger, N. E. Vanderborgh, and T. E. Springer

Los Alamos Scientific Laboratory

Los Alamos, NM 87545

ABSTRACT

Optimized stimulation of georesource reservoirs requires a thorough understanding of the physical, chemical, and mechanical properties of the bed, of the systems and engineering problems associated with field execution, and of the complex technical and economic relations between permeability and production. In support of the Morgantown Energy Research Center and the Eastern Gas Shales Project, the Los Alamos Scientific Laboratory has undertaken an integrated research program touching on all these aspects of the problem. Specifically, the program includes

a) Dynamic Rock Response. Hugoniots, dynamic spall strengths, wave profiles on shock and release, and ultrasonic elastic constants have been determined as functions of material density and bedding orientation for Devonian shales. These data form the basis of predictive explosive stimulation technology.

b) Explosively-Driven Jets. Weapons-developed shaped charges using heavy metal liners are being investigated for downhole use in order to produce a horizontal manifold system leading to a central borehole. Applications of the paths produced by these devices include intersection of the natural fracture patterns, explosive or chemical emplacement, or producing hydrofractures displaced from the borehole.

c) Laser Pyrolysis. Pulsed laser heating results in a rapid deposition of precise quantities of thermal energy into selected shale volumes. Such laser-induced pyrolysis forms the basis for a rapid assay technique which can be used at the wellhead or as a downhole logging tool.

d) Computer Simulation. A computational technique using a hybrid (analog and digital) computer is being developed with the ultimate objective of simulating proposed extraction technologies to establish optimum economic stimulation methods.

Three of these program elements are discussed in the following sections.

Prepared for ERDA under Contract Nos. BB-01-02-02 and BB-01-02-04.

I EASTERN GAS SHALES UNDER DYNAMIC STRESS

Successful prediction and optimization of explosive effects in geologic materials requires a thorough knowledge of the constitutive relations governing the relation of rock response to impulsive loading. Such constitutive relations must include description of both wave propagation and fracture phenomena under dynamic stress. The initial phase of our program therefore was directed toward acquiring these basic data. Here, some of the dynamic properties of gas shales and the techniques used to determine them are discussed.

ELASTIC PROPERTIES

The determination of the elastic constants of gas shales is the first step towards understanding the shale's response to both static and dynamic stresses. The samples whose dynamic properties are presented here were obtained from only two pieces of 4-inch-core from the Columbia Gas Company Well No. 20402, one from approximately 1040 m and the other from 1093 m below the surface. X-ray diffraction patterns showed both to be common illite shales where the composition is very fine silica or quartz grains and a minor amount of anhydrous clay minerals. The densities of the two pieces are 2.7 Mg/m^3 (1040 m in depth) and 2.4 Mg/m^3 (1093 m). These densitites span a commonly accepted bulk density of 2.55 mg/m^3 for eastern gas shales.

The symmetry of the elastic properties of eastern gas shales is transverse isotropic. This means that there is an elastic symmetry axis of rotation perpendicular to the bedding and an elastic axis of two-fold symmetry in the bedding planes.

The samples were prepared for sound speed measurements by cutting them into plates 30 to 60 mm in diameter and 2.0- to 7.5-mm-thick at angles 0°, 45°, and 90° to the bedding. Densities were determined using the submersion method. The sound speeds were determined from the difference in time an ultrasonic pulse took to traverse an aluminum plate and the combination of the same aluminum plate and a gas shale plate. Because of interferences of the ultrasonic pulses at the shale bedding interfaces, only first pulse arrivals were measured. Specifically, an aluminum plate is set between the transmitting and receiving 22-mm-diameter transducers (10 MHz x-cut quartz for longitudinal modes and 5 MHz y-cut quartz for shear modes). The first signal arrival through the plate is set to a fiducial on the screen of a Tektronix 454 oscilloscope, and the received pulse is amplified by a Tektronix 461A wideband amplifier. The gas shale specimen plate is then placed between the transducers along with the aluminum plate. A suitable oil or resin is used to bond all sample-plate-transducer interfaces. The first signal arrival is again reset to the fiducial using the delay-time-multiplier dial of the oscilloscope. The delay or time difference was determined using a time interval meter of nanosecond accuracy and the two gate pulses generated by the oscilloscopes.

We have assumed that the elastic wave velocities are a linear function of density over the density range studied here. This assumption is known to be valid for kerogen-containing Green River oil shales for samples of widely varying density. The linear equations for the five different propagation modes measured are listed below with a description of each.

$$V_1(\text{km/s}) = +1.679 + 1.277\,\rho \qquad \rho = 2.4 \text{ to } 2.7\ \text{Mg/m}^3 \tag{1}$$

(V_1 is the longitudinal velocity directed parallel to the shale bedding.)

$$V_3\ (\text{km/s}) = -1.003 + 1.808\,\rho \qquad \rho = 2.4 \text{ to } 2.7\ \text{Mg/m}^3 \tag{2}$$

(V_3 is the longitudinal velocity directed perpendicular to the shale bedding.)

$$V_4(\text{km/s}) = -1.332 + 1.438\,\rho \qquad \rho = 2.4 \text{ to } 2.7\ \text{Mg/m}^3 \tag{3}$$

(V_4 is both the shear velocity directed perpendicular to the bedding of the shale, and the shear velocity directed parallel to the bedding with particle motion perpendicular to the bedding.)

$$V_5(\text{km/s}) = +1.151 + 1.245\,\rho \qquad \rho = 2.4 \text{ to } 2.7\ \text{Mg/m}^3 \tag{4}$$

(V_5 is a quasi-longitudinal velocity directed at 45° to the bedding.)

$$V_6(\text{km/s}) = +1.416 + 0.627\,\rho \qquad \rho = 2.4 \text{ to } 2.7\ \text{Mg/m}^3 \tag{5}$$

(V_6 is the shear velocity directed parallel to the bedding with the particle motion also parallel to the bedding.)

The velocities are converted to the elastic moduli of a transverse isotropic solid by the following relations,

$$C_{11} = \rho V_1^{\,2}$$

$$C_{33} = \rho V_3^{\,2}$$

$$C_{44} = \rho V_4^{\,2}$$

$$C_{66} = \rho V_6^{\,2}$$

$$C_{12} = C_{11} - 2\,C_{66}$$

$$C_{13} = [(.5C_{11} + .5C_{44} - \rho V_5^{\,2})(.5C_{33} + .5C_{44} - \rho V_5^{\,2})/.25]^{1/2} - C_{44}$$

$$B\ (\text{bulk modulus}) = (C_{33} + 2C_{13})^2/(C_{33} + 2C_{11} + 2C_{12} + 4C_{13}).$$

The elastic moduli and bulk sound speed for the two density shales studied here and for the average bulk density shale are listed in Table 1.

DYNAMIC TENSILE STRENGTHS

In a shock wave's divergent propagation from both spherical and cylindrical symmetries, the initial positive compression rapidly converts into tension. This dynamic tensile stress is a major cause of fracture in the surrounding rock. Another form of fracture, though minor, caused by dynamic tensile stress is spallation. Spalling occurs behind a free surface at which a finite shock wave releases; the resulting rarefaction wave from the free surface and rarefaction wave following the shock collide and form a spreading tension wave. Thus, the dynamic tensile strength of rock is an important property to be determined when attempting to predict the fracture pattern of a rock. Here a technique is described for determining the dynamic tensile strength of gas shales and the results of studies using this technique are presented.

The technique involves impacting shales of known shock impedance and bedding orientation with a thin driver of known shock impedance generating a well-defined shock in the shale. The impedance of the impactor plate is chosen so that the interface between the impactor and the sample separate after passage of the rarefaction wave from the rear free surface of the impactor. If the experimetal configuration is properly designed, the rarefaction from the impact surface of the shales and their other surface which is free interact in the middle region of the shale samples, creating a tension wave. The target plate in which the shale samples are mounted is recovered and the shales are removed and examined for spall. The experimental configuration is shown and described in Fig. 1.

The impactor plate used is polymethyl methacrylate (PMMA), $\rho_0 = 1.186$, its thickness chosen to cause collision of the rarefactions midway through the gas shale. Since the shock velocity in shales are within a few percent of their elastic longitudinal velocities at these stress levels, it was assumed the stress P induced in the gas shale samples is approximately

$$P = \rho C_L U_P \qquad 6)$$

where ρ is the density of the shale, C_L is the measured elastic longitudinal velocity, and u_p is the particle or interface velocity between the PMMA and shale. Since the stress levels induced were approximately 100 MPa (0.1 GPa, 1 kilobar), the stress induced in the PMMA impact plate is approximately

$$P = \rho C_B (U_D - U_P) \qquad 7)$$

where ρ is the density of the PMMA, C_B is the bulk elastic velocity as determined from the PMMA Hugoniot (C_B = 2.598 km/s), U_D is the particle or interface velocity before impact and U_p is the particle or interface velocity. At impact, both the stress and the interface velocity in the gas shale and the PMMA at the interface are the same. If the shock wave in the gas shale is not overtaken by the release wave, and the thickness of the impact plate is such as to prevent this, the magnitude of the maximum tension induced in the sample should nearly equal the maximum stress.

$$\text{Tension} = -U_D \frac{(\rho^s C_L{}^s)(\rho^p C_B{}^p)}{(\rho^s C_L{}^s)+(\rho^p C_B{}^p)} \qquad 8)$$

where the s subscript denotes gas shale and p denotes PMMA. Both the density and elastic longitudinal velocity of each shale sample are determined before each impact experiment, and the impact plate velocity is determined during the experiment (Fig. 1), thus the tension induced in each sample can be readily calculated.

The diagnosis of an impact experiment is straightforward. The target plate is recovered in a large rag-filled tank, its back is removed and the gas shale samples are pressed out. Each shale is then examined for spalling. It was found that shales having a density of 2.69 Mg/m^3 would not spall under tension as high as 66 MPa (0.66 kbars) if the tension waves propagated along the bedding, but shales of a similar density, 2.57 Mg/m^3, spalled as low as 45 MPa (0.45 kbars) if the tension waves propagated perpendicular to the bedding. For shales having a density of 2.40 Mg/m^3, the tensile strengths were less than 40 MPa for both propagation directions. The stress rates involved in these experiments are of the order of 1 GPa/μs (10 kbars/μs) and regions under tension remain in tension only about 2 μs if they do not spall. Experiments involving lower stress rates and longer tension durations would find the tensile strengths of the gas shales to be smaller.

RESPONSE TO PLANE STRESS IMPULSES

Properties of gas shales in response to dynamic stress can best be determined from the analysis of the degradation of finite stress impluses as they pass through the shales. Various techniques and analyses are currently used by various laboratories, many of them originating at the Stanford Research Institute and the Sandia Laboratories at Albuquerque.

The technique used here is to measure the stress history of an impulse at several depths in a shale sample. The sample assembly consists of a stack of plates all 40-mm in diameter. The first plate is 2-mm-thick, the second and third plates are 4.5-mm-thick; and the fourth is 5-mm-thick. The impactor plate is usually 3-mm-thick. The density, elastic properties, and orientation of all plates are matched. Between the shale plates of the sample assembly are 50-ohm grids of 0.01-mm-thick Manganin foil that cover an area of 40 mm^2 in the center region of the plates. The resistance of the grids are well defined as a function of stress under impact conditions. The resistance is deduced from the voltage generated at the null point of a pulsed Wheatstone bridge caused by the change in resistance of the manganin grid. The sample-manganin gage stack is placed in a target plate and surrounded by velocity pins. The entire assembly looks much like that in Fig. 1 except that the 6 small samples are replaced by the stack, and the PMMA plate mounted on the hollowed Al projectile is replaced with copper plates for high stress levels and aluminum plates for low stress levels.

In the upper left diagrams of Figs. 2 and 3 are typical stress histories such as were recorded in a number of experiments on the gas shales.

The difference between the two experiments is the stress levels. The response of the shales to the shock loading and unloading was calculated using a computer code, GUINSY2, written by Lynn Seaman of Stanford Research Institute. The theory on which the code is based and an explanation of how the code is used was earlier described by Seaman (1). The analysis requires the stress histories, a correlation of regions on the stress profiles, the initial density of the shales, and the initial gage locations. From the analysis the specific volume, the particle velocity, and internal energy of the shales are correlated with the stress as a function of time at each gage location. In the remaining diagrams of the figures are plotted particle velocity as a function of the loading and unloading stress, strain as a function of the loading and unloading stress, and the loading and unloading wave velocity as a function of particle velocity.

HUGONIOTS OF EASTERN GAS SHALES

The response of the gas shales to large shocks, between 10 and 100 GPa, was determined from simultaneous measurements of the shock wave velocities through gas shale samples and through a standard material whose Hugoniot (equation of state under shock compression) is well known. The experimental technique is described in detail elsewhere (2). From the measured shock velocities through both the shales and the standard, the mass or particle velocities through the shales are deduced.

The state of gas shale is completely defined by knowing only the shale's initial density (ρ_o), the shock velocity (U_s), and the particle velocity (U_p). The pressure (P), compression ($1-V/V_o$), and change in internal energy (ΔE) for the shale are derived from the above three parameters using the Hugoniot relations

$$P = \rho_o U_s U_p \qquad 9)$$

$$V/V_o = (U_s - U_p)/U_s \qquad 10)$$

$$\Delta E = P(1-V/V_o)/2\rho_o \qquad 11)$$

The locus of U_s, U_p points for material not undergoing transitions in structure or bonding and not influenced significantly by rigidity effects is linear,

$$U_s = c + s\,U_p \quad . \qquad 12)$$

The data plotted in figures 4-7 can be fit satisfactorily with two linear fits with a break between them at approximately $U_s = 5.75$ km/s. This indicates that there is a discrete reduction in the volumes of the shales at the pressure associated with that shock velocity, 20 GPa. The volume reduction at that pressure between the two Hugoniots is 6% for the 2.4 Mg/m^3 shales and 7% for the higher density shales. Since the major component of the gas shales is quartz (30% to 60% by volume) the change in volume can probably be attributed to the α-quartz to stishovite phase transformation. The transition pressure found here is 6 to 10 GPa above the quartz-stishovite pressure where the transition occurs at 25°C (extrapolated from high temperature, static high pressure data) and occurs under shock compression, respectively. There are several explanations for this difference. The first is that the quartz, floating in a matrix of kerogen and other minerals, requires time to attain an equilibrium pressure and to transform, resulting in a shock wave, whose velocity is measured, being followed by a relaxation wave caused by that transition. Below 20 GPa the shock wave is not overrun by the relaxation wave for sample thickness used here, 5 mm. The other explanation is that because of shock heating caused by pore collapse and compression of the kerogen, the normal equalibrium transition pressure for quartz is shifted to higher pressures. The knowledge of which explanation is correct may be important since the first explanation would mean that the shales may be able to absorb large amounts of energy at pressures as low as 10 to 14 GPa.

In addition to the transition pressures not being at equilibrium, the lower pressure Hugoniots are also not at equilibrium. For equilibrium, the constant term in the linear relation (12) is also the bulk sound speed. Comparing the bulk sound speed values in Table 1 with the intercepts in Figs. 4-7, one finds the intercepts to have much higher values. The Hugoniots determined for these shales at low pressures are a combination of equilibrium compressions of the shale constituents and strong elastic components. The elastic influence is evident in a comparison of the longitudinal elastic wave velocities of the higher density shales and their U_s, U_p intercepts.

The high pressure Hugoniots (the upper linear U_s, U_p fits in Figs. 4-7) all agree well. However, all the data seem to show systematic upward curvature when compared with their linear fits. This probably indicates transitions in one or more of the minor components of the shales masked by the monotonic compressions of the remainder of the components.

II HYBRID COMPUTER FLOW MODEL DEVELOPMENT

In conjunction with the explosive stimulation-jet penetration program for Eastern gas shales, we are developing a gas flow modeling capability in which the geometry, permeability and porosity are functions only of space, not time, during the flow process. Because the particular geophysical description of the shale may not be known, description may be given in terms of probability distributions for fracture density and width, permeability, porosity, thickness, etc. In this case it would be advantageous to solve an ensemble of flow problems, determining the expected value and distribution of gas flow. The LASL hybrid computer facility is ideally suited for solving large numbers of gas diffusion problems in a non-homogeneous, non-isotropic medium in two dimensional cartesian or cylindrical geometry. Demonstration of the hybrid computer's capability of solving these problems is an immediate objective of the program.

In order to establish the capability of simulating gas flow in Devonian shale, tools are being acquired and developed on both the CDC 7600 digital computer and on the hybrid computer. To provide cross checks and to provide interim simulation capability while the hybrid computer model is being developed, SIMPAC, a general purpose diffusion code, was obtained from the Morgantown Energy Research Center. Only the portions of SIMPAC needed for compressible gas diffusion are currently being used. SIMPAC was modified to allow two dimensional cylindrical geometries as well as three dimensional cartesian geometries to be defined.

The diffusion of gas in a permeable medium is given by the relation

$$\frac{\partial \frac{P}{z}}{\partial t} = \frac{1}{\phi} \nabla \cdot \frac{k}{\mu} \frac{P}{z} \nabla P \quad . \qquad 13)$$

where P is the pressure; z, the gas compressibility factor; ϕ, porosity; $\frac{k}{\mu}$, the permeability-viscosity ratio; and t, time. A hybrid computer program to solve this equation in one dimension has been completed and a two dimensional program is currently being implemented. The one dimensional model contains most of the features that the two dimensional model will contain and has guided the implementation of the latter. The continuous time discrete space CTDS method is used. The reservoir is partitioned into discrete volumes or nodes. The original partial differential equation has been reduced to a set of ordinary differential equations whose initial conditions are known. In the one dimensional demonstration model the compressibility factor z is assumed to be unity. The equation for the i^{th} node is

$$\frac{dP_i}{dt} = \left[A_{i+\frac{1}{2}} \left(P_{i+1}{}^2 - P_i{}^2 \right) - A_{i-\frac{1}{2}} \left(P_i{}^2 - P_{i-1}{}^2 \right) \right] B_i \qquad 14)$$

where

$$A_{i+\frac{1}{2}} = \frac{1}{\left(\frac{\mu}{k}\right)_i \Delta X_i + \left(\frac{\mu}{k}\right)_{i+1} \Delta X_{i+1}}$$

$$B_i = \frac{1}{2\phi_i \, \Delta X_i}$$

Figure 8 illustrates a simplified analog computer circuit to represent Eq.(14). To make effective use of the hybrid computer it is necessary to time share the hardware. The pressure and flow history of a portion of the reservoir is determined for the time period of interest. The boundary pressures are recorded and are applied as boundary conditions through time when an adjacent portion of the reservoir is later simulated with the same hardware but with the appropriate transmissibilities for the new portion. Figure 9 describes a slab reservoir used to check the model, its accuracy, sensitivity, and convergence characteristics. Six pressure nodes were implemented on the analog computer and represented either reservoir nodes 1 to 6 or 7 to 12. When the left part was being computed, the real boundary pressure $P_0 = 3.4$ atm was used on the left side and the fictitious pressure P_7 from the previous iteration was used on the right side. When the right part was simulated, the fictitious pressure P_6 from the previous iteration was used on the left side and zero flow or pressure gradient was the real boundary condition on the right side. Table II shows the pressures P_6 and P_7 for the 15 iterations required for convergence at a time of 100 days (100 msec computer time). For the initial iteration, all pressures were assumed equal to 34 atm through time. From this it is felt that 15 iterations will also be required for the two dimensional model. Figure 10 shows a digital computer solution of pressures P_1 and P_6 with hybrid computer results in circules. To check the sensitivity of the recording and playback of the boundary conditions, it was determined that an 0.3% full scale error in the analog to digital converter zero adjustment resulted in a 2.8% error in P_6 at the end of 100 days. Thus careful calibration or compensation of the analog digital converter is necessary for the two dimensional problem. Using the one dimensional results, the two dimensional solution time is estimated at 16 seconds per problem.

The two dimensional model requires four analog computer consoles, two Electronic Associates,Inc. 680's and two 7800's. A 15 by 12 array of pressure nodes will be solved by sharing a 5 by 4 array three times in each dimension. Two of the four consoles have already been wired and the digital computer code to store and play back boundary pressures, change transmissibilities, and operate the analog consoles has been written. Hardware modifications to our equipment have been completed which make 16 digital to analog multipliers available (87 needed).

III PULSED LASER-INDUCED PYROLYSIS FOR THE CHARACTERIZATION OF DEVONIAN SHALES

The development of the Devonian shales as an expanding resource for natural gas and petroleum-substitutes requires a greatly increased understanding of this geological region. Consequently a major component of ERDA's Eastern Gas Shales Project is to characterize the shale resource. The laser-induced pyrolysis activity at Los Alamos Scientific Laboratory is one part of that activity.

Limited inorganic geochemical information has been published concerning certain regions in the Devonian shales, particularily the Chattanooga Shales (3); less is known about the organic material incorporated in these formations. Although the thrust behind the current activity is to maximize gas production, as various other processing options are considered the knowledge of particular organic parameters will be needed. Total organic carbon, the carbon/hydrogen ratio, the nature of the carbonaceous matrix (terrestrial-marine origin), the oil yield upon retorting are the most significant. The LASL program seeks to develop new methods to rapidly determine this necessary data.

The organic geochemistry of these shales suggest that progenitors were essential terrestrial and that the basic organic material resembles coal of a low rank. Moreover, it has been concluded that methane, possibly the product from degradation of cellulose-type materials, is dissolved in this coaly fraction (4). One can expect, however, wide variations in the total organic content as well as organic type. Most likely, the selection of a particular processing option will be influenced by the types of organic compounds present in a candidate horizon.

Laser induced pyrolysis is a convenient method for the rapid and precise characterization of naturally occurring carbonaceous materials. Work on Green River oil shales (5,6) and various coals (7) has shown the general applicability of this approach. The experiment is shown schematically in Figure 11. The shale sample, either taken from a core section or drilling chips, is placed in the sampling chamber. Typically, analysis is done on small segments less than 1 cm^3 in volume; only a small fraction of this, approximately 5 mg, is consumed during the analysis. The pulsed laser energy, 5-10 joules of 1.06 μ light with a pulse width of approximately 10^{-3} seconds, is deposited into a small volume segment. Upon the termination of the pulse, a series of products are swept from the sampling chamber into instruments for analysis.

Two types of product result (8). One, a series of low molecular weight gases, is derived from the thermal quenching of the laser-induced plasma (9). The plasma, a high temperature ensemble of atomic and molecular fragments, quenches rapidly after the pulse, rapidly enough to "freeze" out a molecular distribution that existed in kinetic equilibrium at the elevated temperature. Consequently, one can use the composition of these low molecular weight gases to learn about the atomic composition of the shale. For instance, the ratio of C_2H_2/C_2H_4 has been shown to be a convenient measure of the C/H ratio of the sample. The second type of product consists of larger molecular weight fragments and volatile molecular species that result from the combined acoustical and thermal shock wave that travels through the sample during the pyrolysis event. These products, like the cracking patterns found in mass spectrometry, are characteristic sections resulting from thermal fragmentation of unique molecular types (10).

Several distinct types of analysis will be explored with this method:

1. Gas Yield The initial thrust behind the EGSP is to inventory the resource for gas, i.e., to determine the recoverable gas yields. Theory suggests that laser-induced pyrolysis yields will produce essentially no methane from the thermally quenched plasma. Rather product methane results from thermal shocking of a unique volume element and will represent the methane that is released during the physical alteration of the sample.

2. Total Organic Carbon The amount of acetylene produced has been shown to be a indicator of the total organic carbon in Western oil shales. One would expect that this measurement would be equally valid in these candidate materials.

3. C/H Ratio The atomic carbon/hydrogen ratio is a particularily informative measure of the type of organic carbon and the possible process options. This measurement will also be made on a variety of different shale types.

Laser pyrolysis is a uniquely different approach for organic geochemical measurements. It offers, due to the nature of the pyrolysis event necessary, a degree of reproducibility. It also is a rapid technique, one that can be done in only a few minutes, especially if the analysis of the low molecular weight gases emanating from the plasma are of primary interest. Lasers can also be focused to interact with specific volume segments so that unique geometric regions in a sample can be analyzed. This permits analyses across geological features, such as bedding planes and even, perhaps, in a down-hole mode.

The program will initially concentrate on the development of standard techniques for the rapid determination of gas and oil yields. These experiments will utilize core sections in laboratory conditions and field measurements on drilling chips. Correlations between laser pyrolysis results and standard Fischer assays, like those that have been previously done on western oil shales will be determined. Following these preliminary investigations, laboratory and field measurements will be completed to additionally characterize the types and quantities of organic constituents in these shale samples.

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FIGURES

Fig. 1. A front view of a target plate (a) and a cross-sectional view of an impact experiment (b). The view, (a), shows the arrangement of the shale samples in the target plate, machined from Al. Six samples, D, of different densities and orientations are mounted in the target plate, B. Each sample is backed with low density (0.015 Mg/m^3) plastic foam, H, to facilitate mounting the specimens' impact surfaces flush with the target plate's surface. The specimens are held in the plate with a thin layer of epoxy. Shorting pins, C, of various lengths are used to determine the velocity of the impact plate, G. The front surface of the impact plate is covered with a 0.01 mm thick Al foil shorted to the projectile, E. A pulse is generated on a repetative time-marked oscilloscope sweep as each charged pin is shorted. The muzzle of the 3 m long, high pressure gas gun used to drive the projectile is labeled A, the target plate mounting screws are labeled I, and the unsupported area behind the impact plate is labeled F.

Fig. 2. Response of gas shale (ρ = 2.72 Mg/m^3, θ = 0°, C_L = 5.01 Km/s) to high stress planar shock loading and unloading.

Fig. 3. Response of gas shale (ρ = 2.73 Mg/m^3, θ = 90°, C_L = 3.79 Km/s) to high stress planar shock loading and unloading.

Fig. 4. Hugoniot of gas shale (ρ = 2.40 Mg/m^3, θ = 0°, C_L = 4.74 Km/s) to 80 GPa.

Fig. 5. Hugoniot of gas shale (ρ = 2.41 Mg/m^3, θ = 90°, C_L = 3. 35 Km/s) to 80 GPa.

Fig. 6. Hugoniot of gas shale (ρ = 2.70 Mg/m^3, θ = 0°, C_L = 5.12 Km/s) to 95 GPa.

Fig. 7. Hugoniot of gas shale (ρ = 2.65 Mg/m^3, θ 90°, C_L = 3.63 Km/s) to 95 GPa.

Fig. 8. Simplified analog computer circuit for Eq. (14).

Fig. 9. Schematic drawing of one-dimensional reservoir model with parameters used in the calculation.

Fig. 10. Digital and analog computer results of model in Fig. 9 for pressures P_1 and P_6.

Fig. 11. Schematic of Laser-Induced Pyrolysis Instrumentation. Sample is enclosed in a 6 mm ID quartz tube.

TABLE I.

ELASTIC MODULI OF EASTERN GAS SHALE

Density (Mg/m^3)	2.40	2.55	2.70
C_{11} (GPa)	54	62	71
C_{33} (GPa)	26	33	41
C_{44} (GPa)	11	14	18
C_{66} (GPa)	20	23	26
C_{12} (GPa)	13	16	19
C_{13} (GPa)	17	17	16
Bulk Modulus (GPa)	16	17	18
Bulk Sound Speed (km/s)	2.60	2.61	2.61

TABLE II.

FICTITIOUS BOUNDARY PRESSURES P_6 AND P_7

DURING CONVERGENCE (100 DAYS)

ITERATION NO.	P_6 (atm)	P_7 (atm)
0	34.00	34.00
1	31.20	31.18
2	28.61	28.61
3	26.27	26.31
4	24.18	24.31
6	20.90	21.27
8	18.82	19.47
10	17.69	18.52
13	17.05	18.01
15	16.90	17.93
16	16.90	17.91

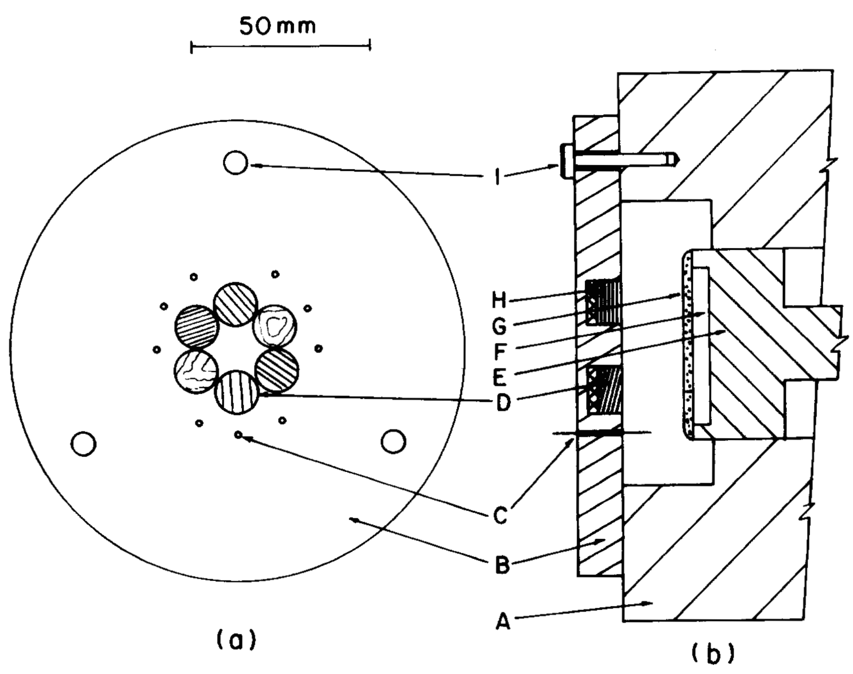

Figure 1

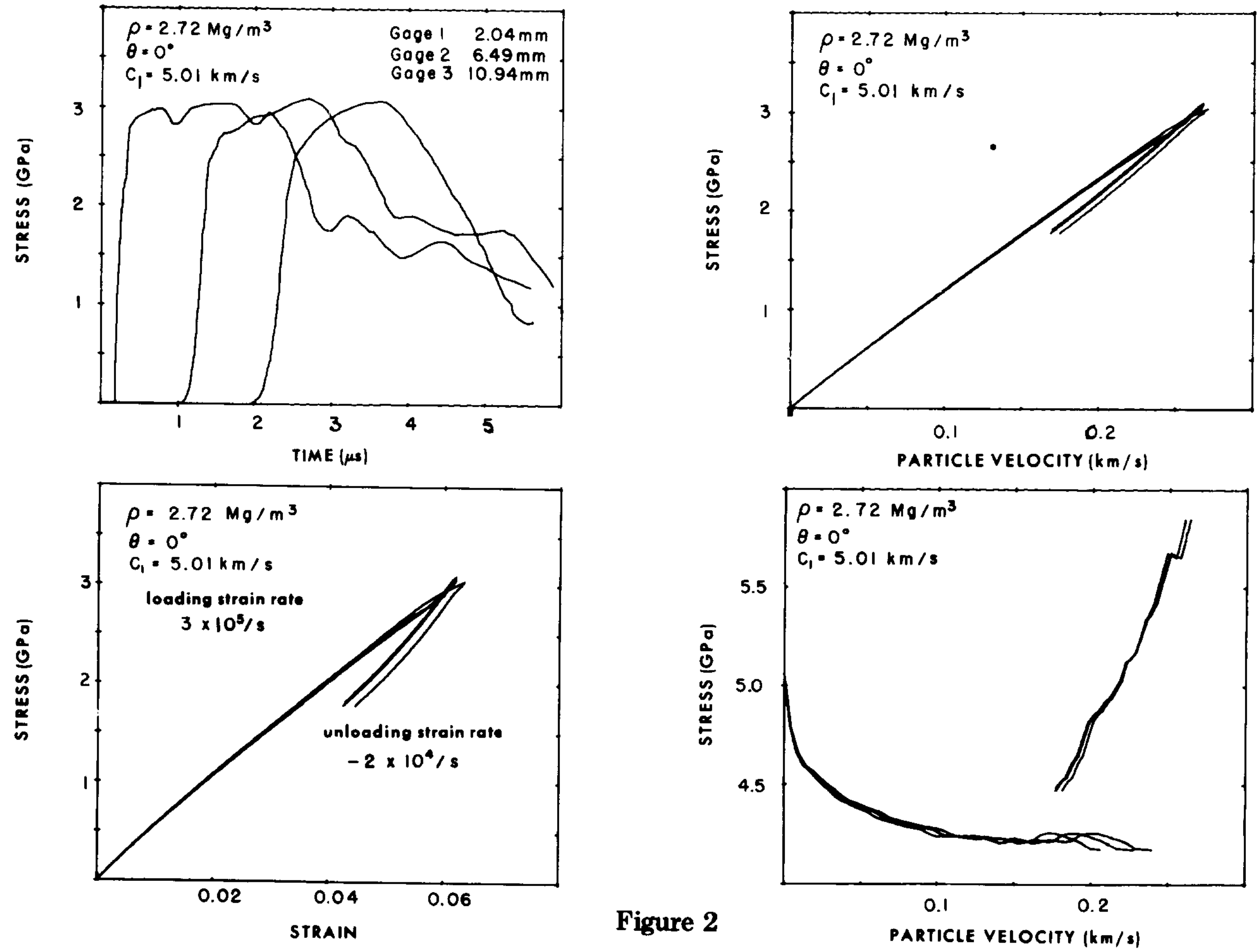

Figure 2

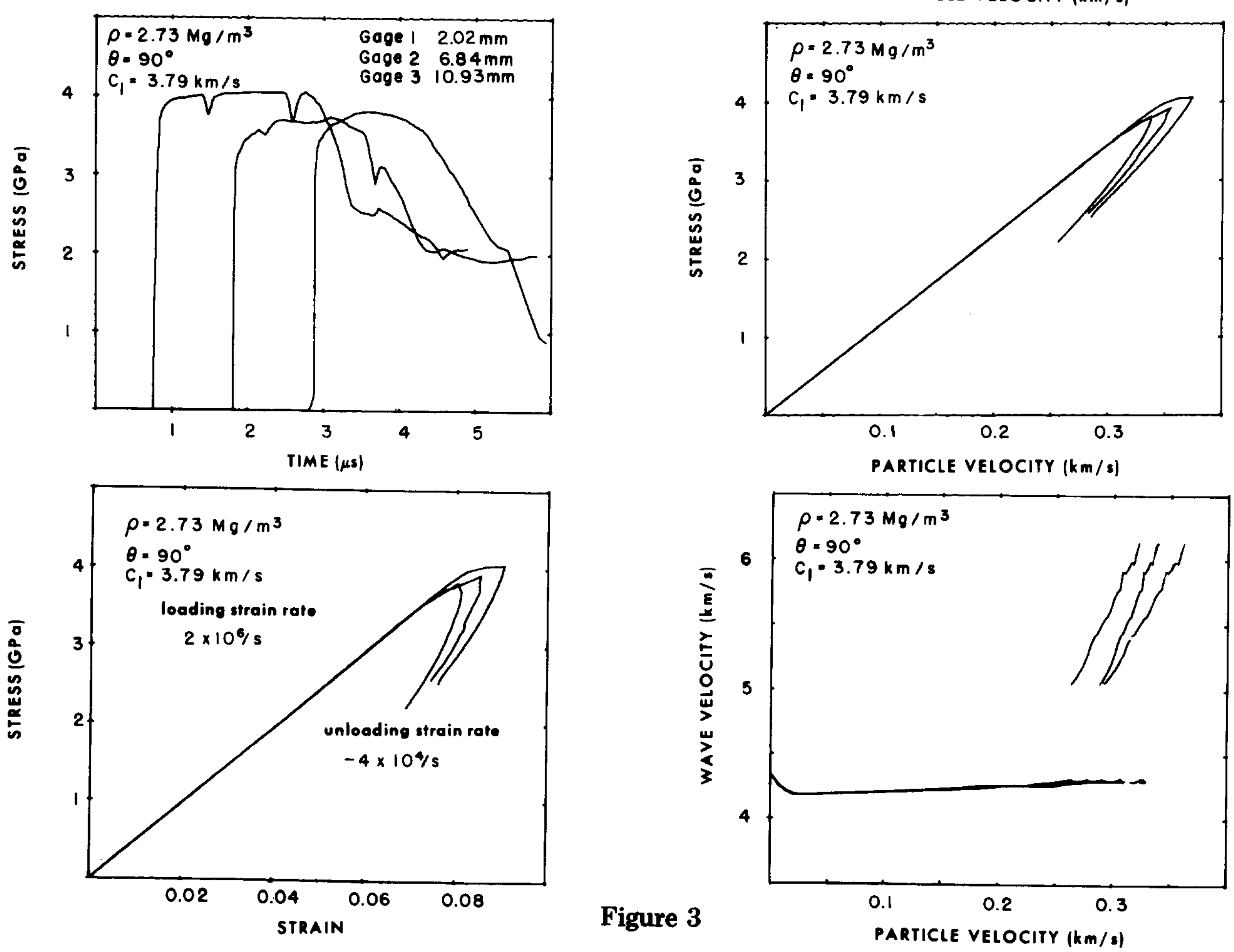

Figure 3

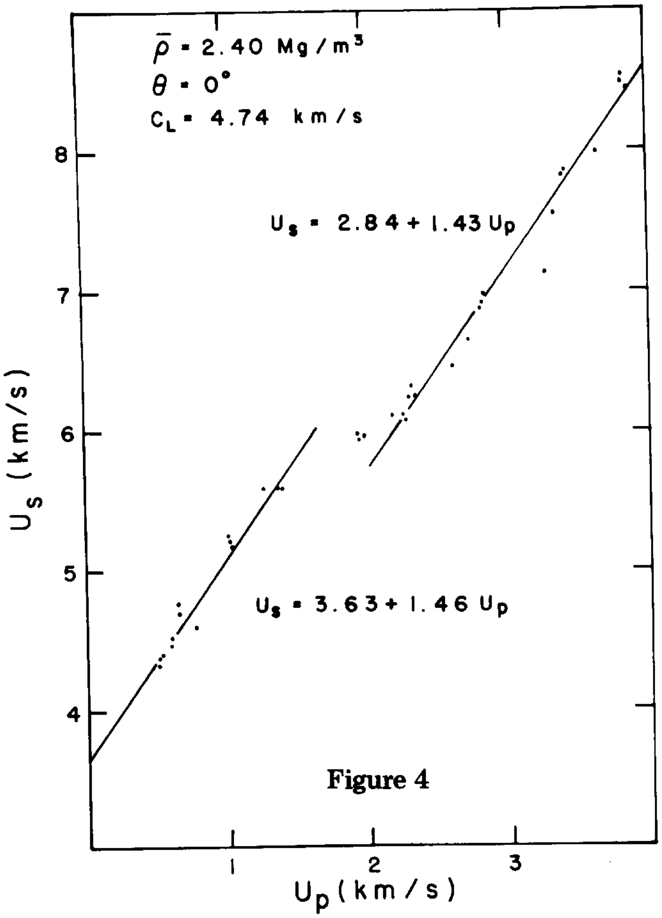

Figure 4

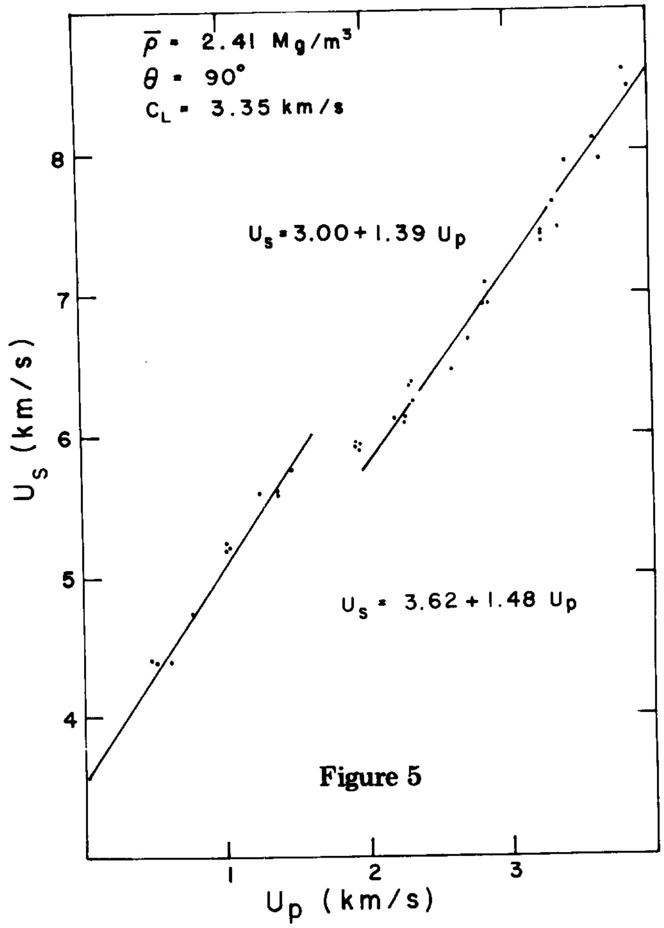

Figure 5

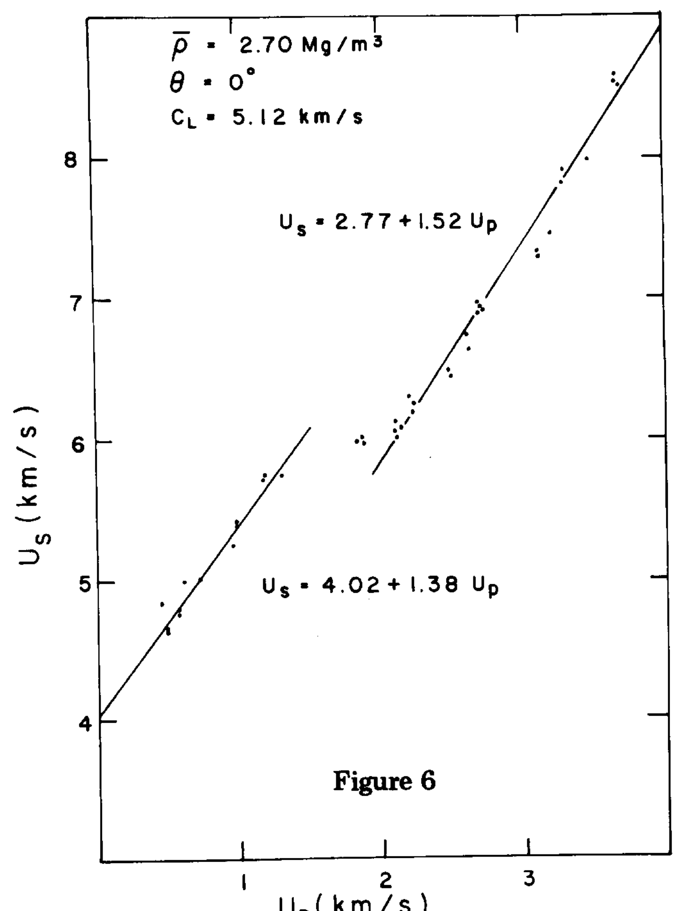

Figure 6

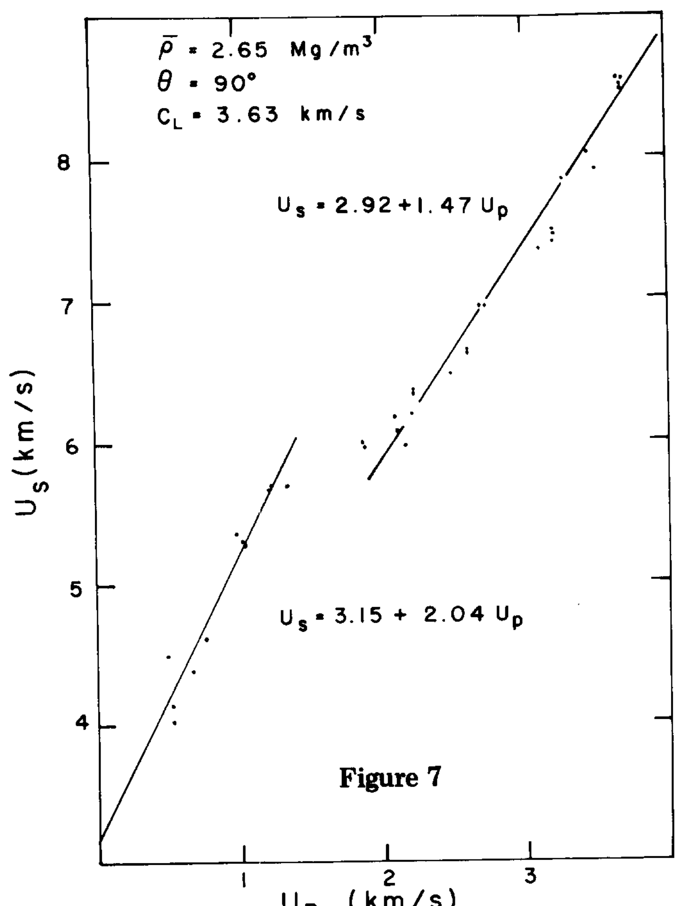

Figure 7

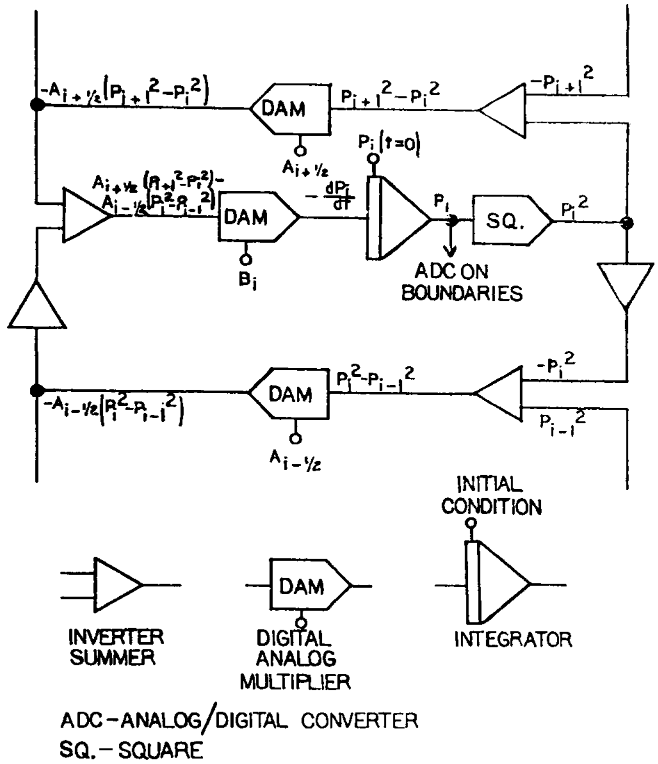

Figure 8

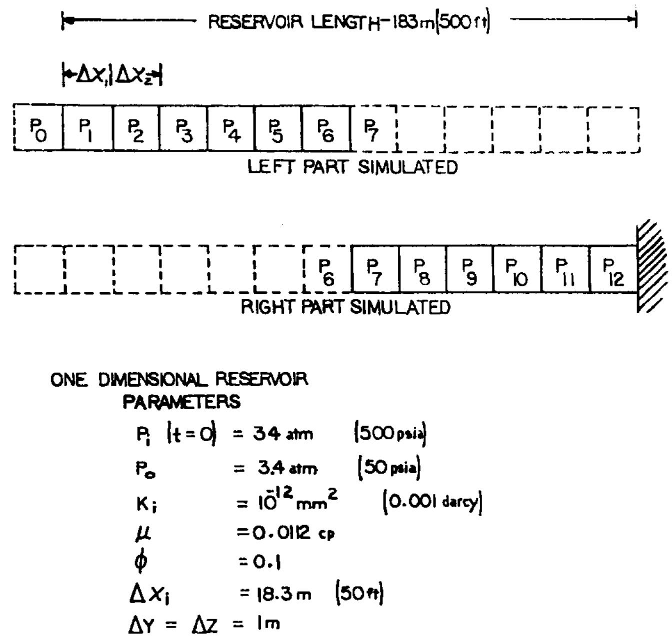

Figure 9

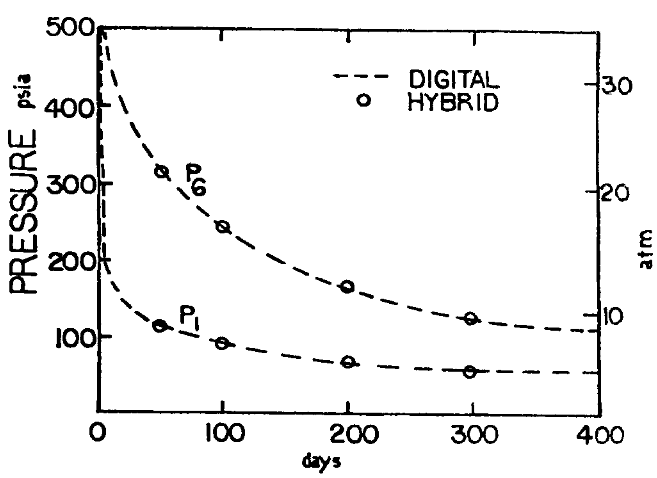

Figure 10

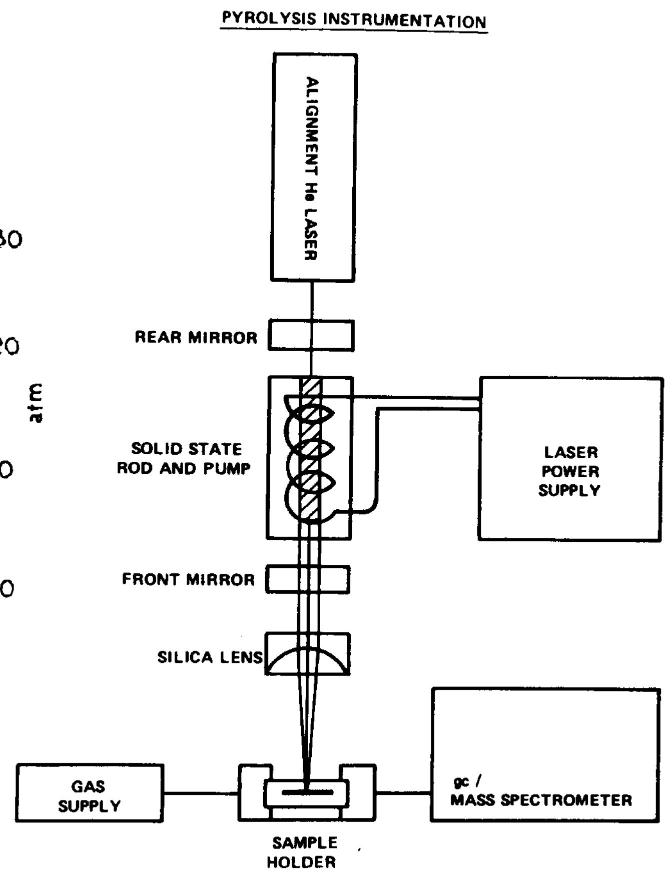

Figure 11

DEFINITION OF FLUID-FILLED FRACTURES IN BASEMENT ROCKS*

by

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ABSTRACT

The Los Alamos Scientific Laboratory Hot Dry Rock Project, under ERDA sponsorship, has studied the attenuation of acoustic detonator signals traversing pressurized water-filled hydraulic and natural fractures. In contrast to those propagated through unpressurized fractures, signals are attenuated in high-frequency components (1-5 kHz) throughout the entire coda, significant scattering is observed, and direct ray paths are changed. The drilling of an exploratory well into the rock volume under investigation confirmed the presence of fractures possessing high fluid conductivity. Confirmation was on the basis of increased flow and temperature anomalies encountered in the exploratory well, and on pressure changes in a nearby pressurized monitoring well.

INTRODUCTION

The Los Alamos Scientific Laboratory, under ERDA sponsorship, is investigating concepts[1,2] for extracting thermal energy from hot dry rock at a demonstration site in Northern New Mexico. A man-made geothermal reservoir was produced by drilling a well into hot, relatively impermeable basement rocks and making high conductance hydraulic fractures. These fractures were subsequently intercepted by a second directionally drilled well. Heat extraction was initially accomplished by water injected into the reservoir through one well and returned through the other. By late 1977 the installation of surface plumbing will enable the completion of a closed-loop circulation system by which pressurized hot water from the production well will be cooled using a heat exchanger and recirculated through the reservoir. A 3 to 5 MW(t) heat extraction experiment will then commence to assess the long-term behavior of the reservoir.

The development of the demonstration site is best described with reference to Figures 1 and 2, which show wellbore geometries in the reservoir between the depths 7800 and 9200 ft.[2] In 1974 an exploratory well designated Granite Test No. 2 (GT-2) penetrated basement at 2490 ft and was drilled to a completion at a depth of 9619 ft in rocks having a temperature of 197°C.[3] In 1975 a second well, Energy Extraction No. 1 (EE-1), was drilled for the expressed purpose of intersecting a hydraulic fracture which had been made at the bottom of GT-2. Due to then inaccurate and imprecise wellbore

*Prepared for ERDA under Contract No. W-7405-ENG-36.

surveys and to erroneous acoustic data, EE-1 was drilled to a completion depth of 10,050 ft having never penetrated the probable locations at which flow between wells through the hydraulic fracture could be directly established. Instead, only a high-impedance connection between wells was observed, unacceptably high for efficient heat extraction.[4]

Even though the wells approached as close as 30 ft to each other, subsequent efforts to establish a direct connection between wells through additional hydraulic fracturing, and by chemical attack proved unsuccessful. It was soon recognized that the inability to improve the system arose from geometric constraints imposed by the relative positions of the two wells. In anticipation of sidetracking one well to optimize geometric relationships between wells, programs were initiated to develop requisite survey methods for precise directional drilling and to define the location and physical dimensions of the fractured rock. The former was accomplished. The latter program focused on methods based on induced electrical potential, induced seismicity,[5] and acoustic attenuation measurements. This article reviews only the acoustic measurements; work on each area continues today.

Early results from these efforts provided sufficient information so that in May and June of 1977 GT-2 was sidetracked into the GT-2A and GT-2B trajectories and intercepted hydraulic fractures communicating directly with EE-1. Those intercepted during the drilling of GT-2B were more conductive and form the present connection existing between wells.

SHOT LINES AND DOWNHOLE INSTRUMENTATION

The projected source and receiver positions occupied during the succession of acoustic attenuation measurements is shown in Figure 1. Horizontal distances represent a four-fold expansion of the depth scale so that angular relationships in projection are distorted. The four shot lines along which measurements were made are shown. These are actually inclined at 45 deg to the horizontal. Previous experience had shown that at this inclination, signals from the source would contain a significant shear wave component.

The upper two shot lines traverse rock dominantly granitic gneiss in lithology; the lower two, granodioritic rocks. Redundant measures of compressional wave velocities by single-well and between-well acoustic surveys give a uniform velocity of 19.2 ± 0.4 ft/msec for both lithologic units. Within the precision of these surveys neither velocity anisotrophy within a unit nor velocity differences between units appears to exist.

The acoustic signals for the attenuation studies were generated by detonations. The signals were detected using a downhole triaxial geophone system developed by Los Alamos Scientific Laboratory.[6] Four Mark Products high-temperature geophones arranged in series comprise an axial set. Signal output from each set was amplified by a battery-operated differential amplifier potted in a silicone rubber epoxy and contained within an ice-filled dewar. The geophones, batteries, and amplifiers operate at 1-atm pressure with a steel housing. Continuous operation at 200°C is possible for periods up to twelve hours.

Coupling of the geophone package is accomplished through a small d.c. motor-driven arm. The arm is driven against borehole walls with a total force of 200 lb. The entire package is 12 ft in length, has a maximum diameter of 6 in., and weighs 120 lb.

The signal source consisted of a string of three high-temperature detonators potted in silicone rubber epoxy and housed within a dumbbell-shaped tool. The ends of the tool served both to centralize the detonators in the wellbore and to partially deflect acoustic energy out of the wellbore. A single vertical geophone placed in the tool above the detonations enabled precise firing time to be established. The detonators' signals were rich in frequency components up to 5 kHz, and therefore were particularly useful.

MEASUREMENT PROCEDURE

The result of the acoustic attenuation study is better understood if the nature of the measurements is clear. The procedure followed on four successive days was:

1. With the GT-2/EE-1 system at hydrostatic pressure (unpressurized), the triaxial geophone system was locked in position in GT-2.
2. The detonator package was positioned in EE-1; three detonators were fired in succession at an interval of approximately ten minutes.
3. The detonator package was reloaded and returned to the former position.
4. EE-1 was pressurized to 1550 psi, 200 psi in excess of the pressure at which fractures in the EE-1/GT-2 system are known to be held open and extended.
5. Three detonators were then fired,completing the measurements along a specific shot line.

A total of six signals traversed a particular shot line; three propagated through an unpressurized system; three through a pressurized system. Of the 24 planned detonator firings, 23 were fired successfully. The station depth and coupling of the geophone package remained unchanged for all measurements along a particular shot line. As evidenced by analysis of signals traversing the 7923-ft shot line discussed below, pressurization of the EE-1 wellbore did not change the characteristics of the source appreciably. Along that shot line no effects attributable to pressurized fractures were observed.

RESULTS

The interpretation of data obtained from the upper two shot lines and that from the lower two are similar. The following analysis relates to a shot line from each pair--the lines initiated by the detonator positions of 7923 and 8675 ft, respectively. Figures 3a and 3b give representative examples of the signals which traversed the EE-1/GT-2 fracture system during times at which it was at hydrostatic and elevated pressures.

The low-frequency signal seen on the vertical records arose from oscillations caused by water flowing past the geophone package during system pressurization. Compressional and shear wave arrivals are clear on most records. Records from the 8675-ft line show that pressurization of the GT-2/EE-1 fracture system significantly modified signal waveforms. Waveforms appear to be changed in the time interval between compressional and shear arrivals, as well as in the remaining portion of the coda. The arrival of the shear wave appears to be delayed or the sense of the consequent first motion reversed. The variation in waveform of signals from the 7900-ft line is small in comparison. The difference between records can be largely attributed to non-reproducible characteristics of the detonator source pulse, and may be used as a measure of it.

The sum of the signal power measured by each triaxial component and averaged for 200-μsec intervals for all signals is given in Figures 4 and 5. The arrival of compressional waves and shear waves is clearly evident. A third arrival occurs at 12 msec in records from the 8675-ft line. After the second or third arrival signal power decays experimentally in each case except that for signals traversing the pressurized system along the 8675-ft line. These signals show no appreciable decay during the first 25 msec of the coda. In the pressurized system scattering structures have been produced which were not present in the hydrostatic system.

The power spectra of all signals recorded on the vertical geophone set from each shot line is shown in Figures 6 and 7. Maxima in the power spectrum occur at frequencies near 600 and 2800 Hz, respectively. Signals traversing the pressurized system along the 8675-ft line show an attenuation of frequency components above 1000 Hz. The loss of the 2800-Hz component implies that attenuating structures were created along this shot line which have a width or characteristic spacing as small as 7 ft.

Pressurization of the system also changed the travel path, or refracted, the direct signals. Hodograms of the compressional wave arrival show that signals traversing the pressurized system along the 8900-ft line deviated from those of the hydrostatic system by 3.6 ± 1.4 deg. Refraction of the direct signal apparently arose from oblique incidence and passage of the signal through a bound volume in which propagation velocities were changed by system pressurization. Comparable determinations could not be made using signals from other shot lines because lower signal-to-noise ratios prohibited measurements of acceptable precision.

GT-2 SIDETRACKING

The foregoing analysis appeared to indicate that a structure of characteristic spacing or width as small as 7 ft, which refracted and scattered acoustic waves, was present in the EE-1/GT-2 system. Furthermore, the structure was intercepted by signals traversing only the lower two shot lines. This structure was inferred, and later confirmed by sidetracking GT-2, to be comprised of fractures induced by reservoir pressurization. In addition, prior to sidetracking the following was known about the reservoir: Seismicity of the N-NW striking fractures could be induced by pressurization.[5] EE-1 was in direct communication (through IZ, Figure 1) with low flow impedance, large surface area fractures.[4]

In May and June of 1977, GT-2 was sidetracked sequentially into the paths shown in Figures 1 and 2. The planned GT-2A trajectory was to intersect, at maximum vertical separation from the EE-1 injection zones, the inferred N-NW fracture system. Drilling proceeded with the EE-1 wellhead pressurized and carefully monitored. GT-2A intercepted a fracture at 8600 ft--a resulting pressure drop was observed in EE-1 along with flow from GT-2A. Figure 8 shows a temperature log taken after termination of drilling in GT-2A. The fracture producing water at 8600 ft is clearly seen as are deeper fractures producing additional water.

The existence of water-bearing fractures was confirmed by the redrilling of GT-2A. However, the impedance-to-flow between GT-2A and EE-1 through the fracture was too large for efficient heat extraction. Further drilling was necessary. GT-2B was drilled to intercept the fracture system closer to the EE-1 injection zones. Low-impedance fractures were intercepted at 8755 and 8860 ft, respectively. Figure 8 shows that most of the flow between wells arises from the upper fracture.

CONCLUSION

The presence of water-bearing fractures created in the reservoir was inferred on the basis of the scattering, attenuation, and refraction of acoustic signals intercepting the structures under pressurized conditions. The observations during the sidetracking of GT-2 into the GT-2A and GT-2B trajectories confirmed this inference. Given the availability of two wells, the capability of detecting a fracture system between the wells now would appear to exist.

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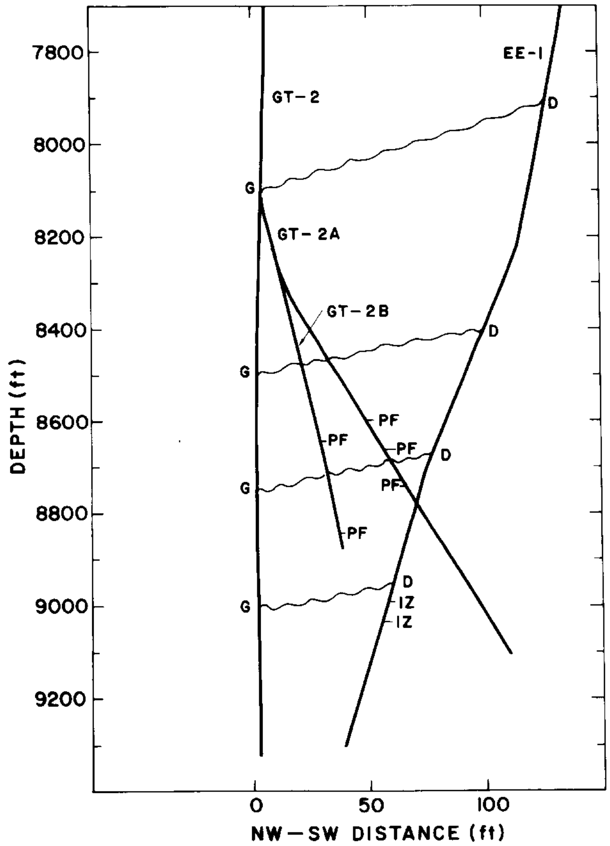

Figure 1. - Projection of well and shot line geometries to the NW-SW vertical plane.

G	triaxial geophone station
D	detonator firing position
PF	pressurized fracture
IZ	injection zone
~	shot lines

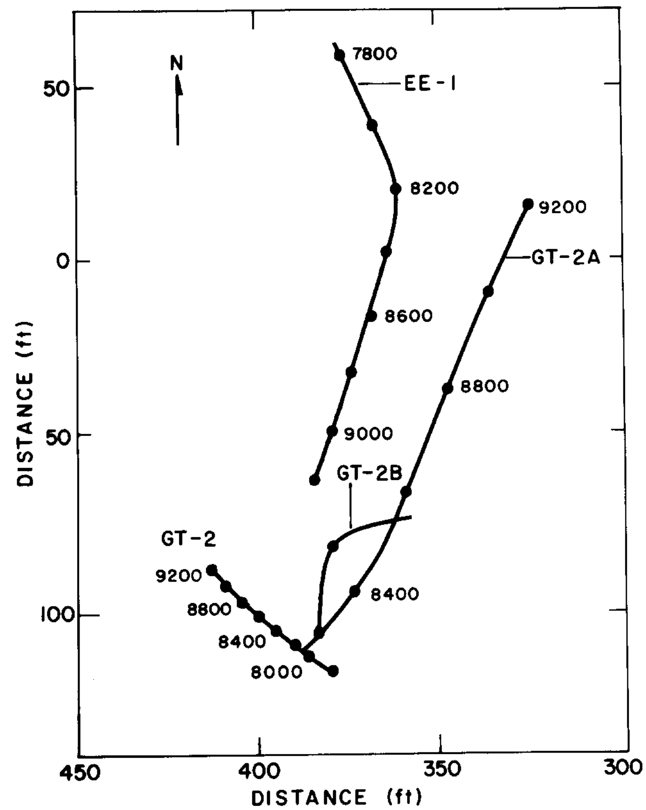

Figure 2. - Projection to the horizontal plane of well geometries between 7,800 and 9,200 ft.

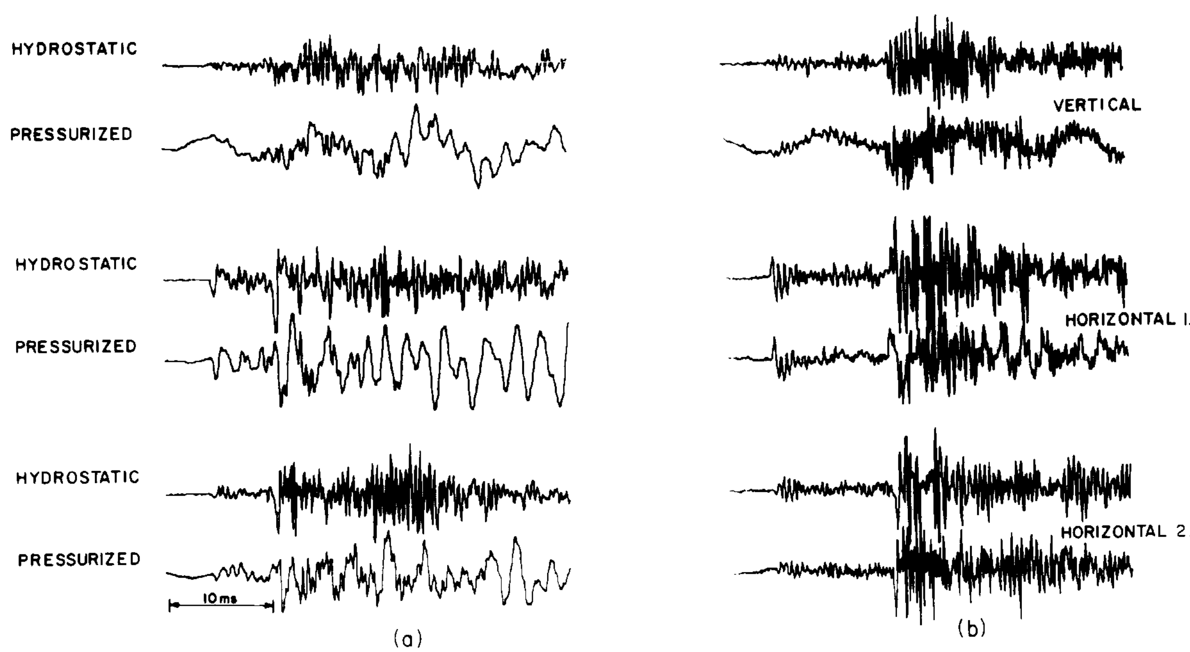

Figure 3. - Signals from the shot lines originating at 8,675 ft (a) and 7,923 ft (b).

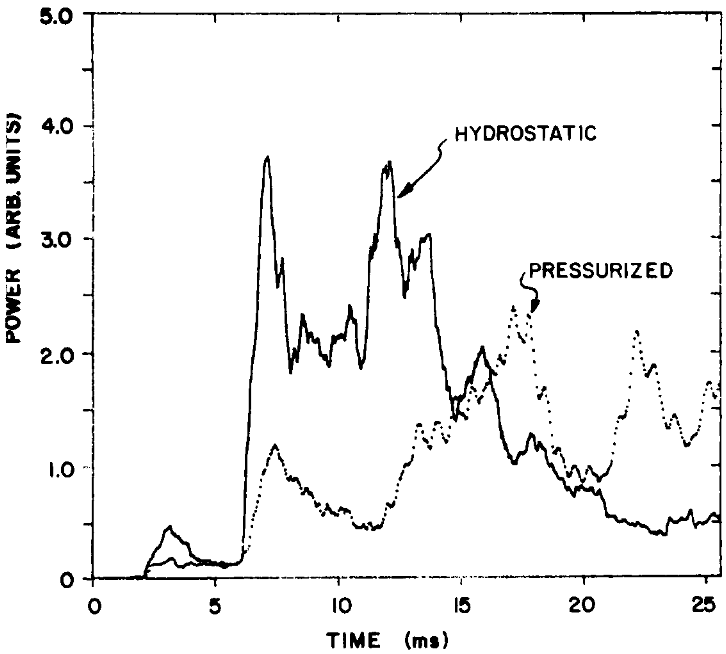

Figure 4. - Average power vs time - each signal, all components, 8,675-ft line.

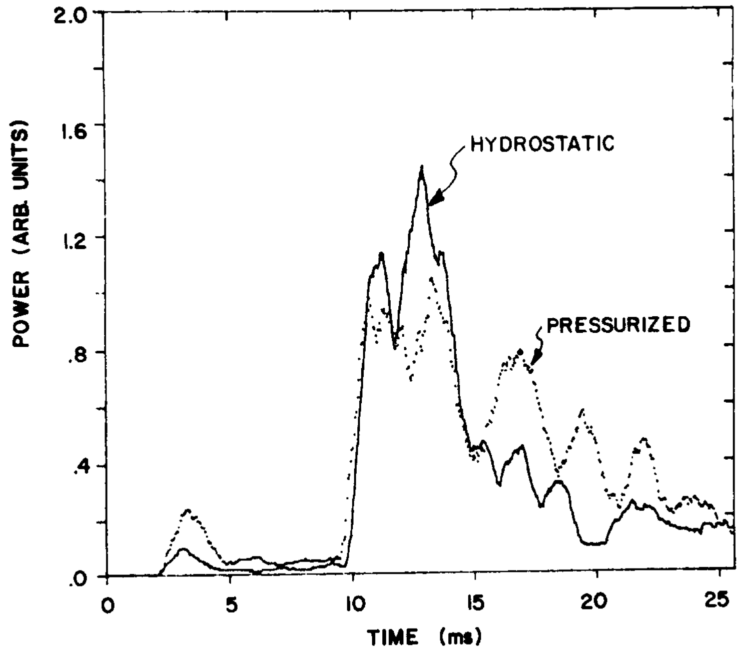

Figure 5. - Average power vs time - each signal, all components, 7,923-ft line.

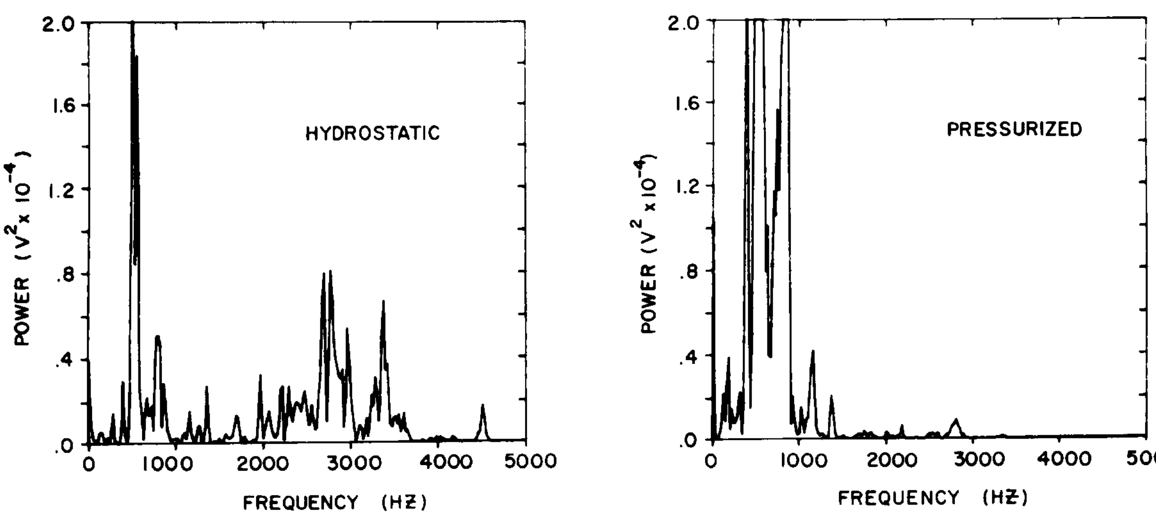

Figure 6. - Power spectrum of all signals recorded on the vertical geophone set, 8,675-ft line.

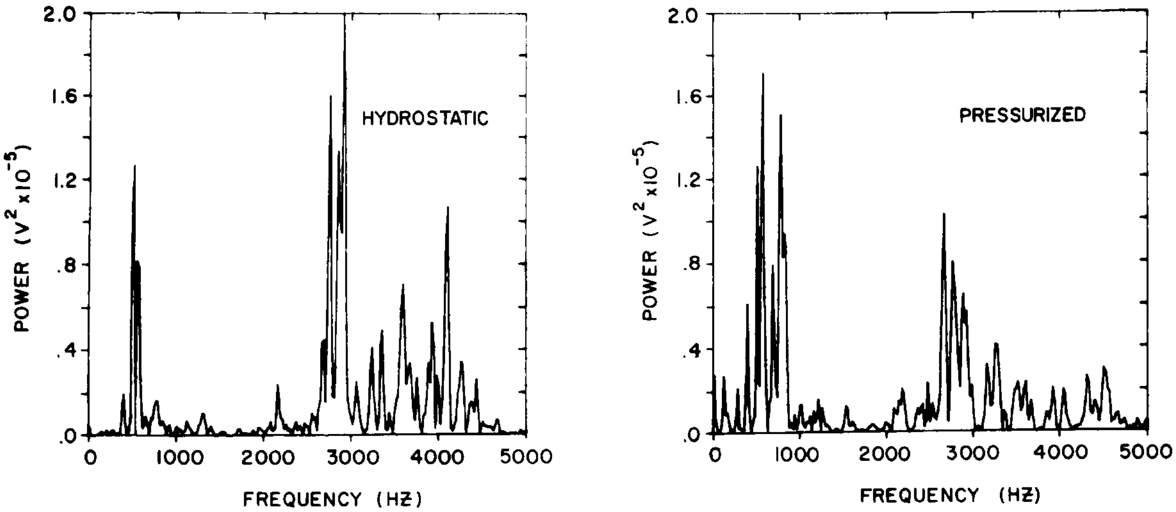

Figure 7. - Power spectrum for all signals recorded on the vertical geophone, 7,923-ft line.

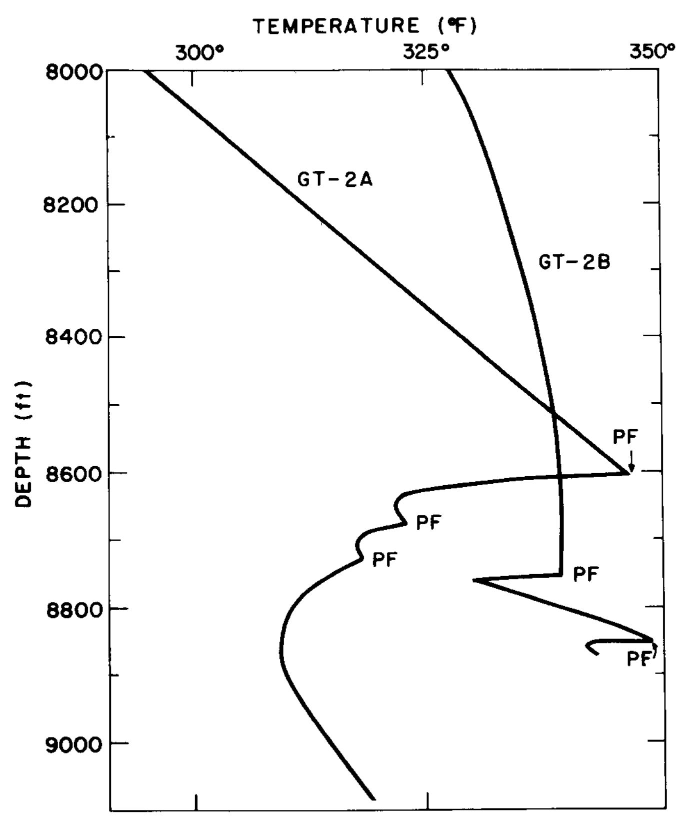

Figure 8. - Post-drilling temperature logs of GT-2A and GT-2B.

PF pressurized fracture

UPDATE ON THE LLL GAS STIMULATION PROGRAM*

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ABSTRACT

This report discusses the progress and current state of the Lawrence Livermore Laboratory research program on the stimulation of tight gas reservoirs. This is primarily a theoretical and laboratory program; however, the application and interpretation of geophysical logging is an essential part of it. The theoretical hydraulic fracturing models in their current state of development show that as the pore pressure is increased, the matrix stress around a fracture becomes more tensile. Laboratory experiments, which use unconfined specimens, show that both the characteristics of a layer and the mechanical properties of the adjacent materials control the fracturing in the region of the layer. We have acquired and interpreted some long-period seismic logging data. The preliminary analysis indicates gas-producing fractures intersecting the wellbore. Other fractures, which are either barren or do not intersect the wellbore, are also indicated by the data. Mechanical measurements of the Devonian shale indicate fairly uniform mechanical characteristics; however, a degree of mechanical anisotropy was noted for sections oriented horizontally or vertically with respect to the shale structure. Reservoir analyses of the Rio Blanco nuclear stimulation experiment and the nearby MHF experiment indicate that characteristic lens dimensions were 40 to 60 ft (12 to 18 m) vertically and 400 to 600 ft (120 to 180 m) horizontally.

INTRODUCTION

Although U.S. gas resources remain large, the proven U.S. reserves have declined to 230 trillion ft^3 (TCF). The current reserves/production ratio is 10 to 1. It is estimated that tight nuclear gas reservoirs and eastern Devonian gas shales contain large quantities of gas, but these resources have been difficult to recover. Some gas has been produced from these reservoirs already, but industry needs more economical recovery techniques.

Several techniques have been used to stimulate gas production. One of the most promising is massive hydraulic fracturing (MHF). MHF differs from hydraulic fracturing, which has been used in oil well completion and cleanup for many years, in that much larger amounts of fluid and proppant are pumped down the well and out into the formation to create and prop fractures at greater distances from the well. Other techniques include high explosive

*This work was performed under the auspices of the U.S. Energy Research and Development Administration under contract No. W-7405-Eng-48.

and nuclear explosive stimulation. They involve detonating explosives underground to fracture the rock and allow production. High explosive stimulation has been used extensively in the Devonian shales, and nuclear explosive stimulation has been tried in three western locations.

The application of MHF techniques to tight gas formations has given variable and sometimes disappointing results. The best efforts of a CER/Industry/Government consortium to stimulate the Piceance Basin near Rio Blanco, Colorado, have not been successful. On the other hand, Amoco has used MHF techniques in the Wattenburg field near Denver with a high degree of success. Significant differences in these reservoirs apparently contribute to the differences in the success ratio.

The Devonian shales present similar problems. It is believed that production from these gas shales results from the connection of the wells to the existing fracture patterns. Hence, the problems here include locating the producing zones, locating the natural fractures near the wellbore, and fracturing from the wellbore to the existing fractures.

The Lawrence Livermore Laboratory has embarked on a research program to help develop tight gas reservoirs in the United States. We are trying to obtain a more detailed understanding of the stimulation processes, including how the formation properties interact with and affect these processes. The problem is to determine how to connect the maximum amount of productive reservoir rock to the wellbore through a highly permeable fracture system. There are several questions that we would like to be able to answer in advance about Rocky Mountain areas. Can we identify particular sections where the fractures may be expected to be preferentially confined to the productive sands, resulting in a maximum volume of reservoir stimulated? What is the geometry (length, width, and number) of the fractures? What is the nature of the treatment (fluid composition, volumes, pumping rates, perforation intervals) which, when applied to a formation of certain properties, will result in optimum and economic recovery. What are some of the important geophysical measurements and experiments that can aid in this endeavor? What data and experiences exist that are relevant? Most of the western reservoirs contain a high degree of water saturation. High degrees of water saturation can significantly reduce the already low permeability of these reservoirs. Is it possible to use existing logging techniques supplemented by new geophysical measurements to ascertain the in-situ water saturation?

Devonian shales are also very low in permeability and therefore present many of the same challenges as the tight Rocky Mountain formations. There are, however, some special problems. Logging techniques for these shales are just being developed, and we have not been able to locate fractures that do not intersect the wellbore by means of standard logs. The effect of the hydraulic fracturing method on Devonian shales is not well understood. Water, one of the standard hydraulic fracturing fluids, can cause significant formation damage; organic and cryogenic fluids are expensive; high explosive fracturing makes well clean-out and completion costly and uncertain, and as we have shown previously,[1] the diameter of permeability enhancement is small. Gas fracturing is a developing art, and it shows promise for application in the shales.

Our program is primarily investigative in nature. No major field programs are currently proposed. We are constructing and applying theoretical models and performing laboratory experiments to develop an understanding of the stimulation processes. However, one facet of the program is directed toward geophysical measurement (logging) to provide insight into the environments where these stimulation processes are applied. Close association with the ERDA-supported field programs will provide the interaction and direction necessary to the program. The LLL program can be broken into seven task areas: (1) theoretical modeling of the hydraulic fracturing process; 2) hydraulic fracturing laboratory experiments; (3) log tool development and application and analysis of log data; (4) cataloging and evaluation of pertinent geological and geophysical reservoir data; (5) measurements of pertinent reservoir properties; (6) reservoir analysis; and (7) evaluation of other stimulation techniques.

THEORETICAL MODELING OF THE HYDRAULIC FRACTURING PROCESS

At the present time, two models are being used. One is designed to analyze the local effects of the hydraulic fracturing process (that is, the effects that control the orientation of the hydraulically created fracture) and the other to calculate some of the long range effects of fracturing processes such as surface deformations and stress fields across layering near the fracture. Results from the latter model are being compared with field measurements[2] to interpret fracture geometries.

The first model is much more complete in that pore fluid flow and pore pressure effects are included with the elastic model of the continuum. The model consists of the numerical solution of the two-dimensional time-dependent porous-flow equations, which overlays a static two-dimensional finite element description of the elastic continuum.[3] This allows the time solution to be controlled by the fluid flow into the fracture, while the static solution follows as a set of equilibrium states at each time step. We ignore the wave effects in the elastic solution. This approximation is valid since the wave speed is much larger than the propagation velocity of a fluid-driven fracture. For example, a fracture is driven on the order of 2000 ft in 5 to 8 h, while an elastic wave traverses this distance in 0.2 s. At present, the coupling between the elastic and flow parts of the code is in the pore pressure effects using the equation generally attributed to Terzaghi:[4]

$$\sigma^1 = \sigma^o - p, \tag{1}$$

where σ^1 is the total stress, σ^o is the solid matrix stress, and p is the pore pressure. The permeability of the fracture is calculated using

$$k = \delta^2/12, \tag{2}$$

where k is the permeability of the fracture and δ is the fracture aperature.

The hydraulic fracturing model, which includes the fluid flow and pore pressure effect is in an advanced development stage, and we will proceed with further development as application warrants. Calculations show that the model can allow a fracture to be pushed open by the fluid pressure and then to close as the fluid is withdrawn. A failure criterion, which would permit fractures to nucleate and propagate has not yet been incorporated into the model.

The model has been applied in several check problems. The effects of the pore pressure on the elastic strain field can be readily seen by examination of Figs. 1 and 2. Figure 1 shows contours of the dilatation shortly after the fracture was pushed open by an injected fluid. Here we note two dilatational or tensional lobes near the crack tips and compressional lobes adjacent to the fracture faces. Figure 2 displays contours of dilatation after the pore fluid has propagated from the fracture into the medium. Here, we note that the compressional lobes have significantly decreased and the tensional lobes are more predominant.

The second model is essentially a static/elastic model. Pore pressure effects are not included. We used this model to study the effect of a layer on the general stress field and surface deflection properties above a vertical hydrofracture. As the problem geometry in Fig. 3 shows, we used half-plane symmetry to simplify the calculations. The layer, typified by Poisson's ratio ν_2, is embedded in a medium typified by Poisson's ratio ν_1. Young's modulus was held constant for both materials. We kept the hydrofracture location and width constant, but varied the layer depth a and the layer width w independently. We made ten calculations, then reversed the Poisson's ratios and redid the calculations. In some calculations, the layer was wholly below the hydrofracture. In most cases, the layer completely or partially contained the hydrofracture. For the problem shown in Fig. 3, we used $\nu_1 = 0.35$ and $\nu_2 = 0.20$.

At the top of Fig. 3 is a plot of the surface vertical displacements we obtained for the layer geometry shown. The general character of this curve was similar for the different cases, but a change in the hydrofracture location or width sometimes shifted the peak of the curve slightly and also caused the amplitude to change. The parallel strain along the surface, when plotted, also exhibited the same general characteristics as the surface displacement curve with the peak corresponding to the peak in surface deflection.

Figure 4 shows the general distortional field in the region of the hydrofracture. The most compressive stress is near the middle of the hydrofracture and the most tensile near the ends of the hydrofracture. Some of the lines have been omitted near the hydrofracture due to the large gradients in that region. The position of the layer is clearly visible on the contour map.

LOGGING

Acoustic velocity logs are often used in finding fractures near the wellbore.[5] We have used them for that purpose in the Devonian shales. A wet-hole tool often used is the variable-intensity-recording continuous-velocity log, marketed under such names as Microseismogram or 3-D log.[6] The data obtained with this log are normally recorded on film that moves past a slit at a rate proportional to the logging speed. An oscilloscope sweeps across the slit with each pulse of the sonde transmitter. The oscilloscope beam is intensity-modulated by the acoustic signal, producing a bright trace for large positive amplitude, no trace for a large negative amplitude, and a medium trace for zero amplitude. This is recorded on the film as light and dark lines, with neutral gray for zero amplitude. Figure 5 shows such a record.

Such logs are satisfactory for locating fractures near the borehole, but since their sweep is generally quite short, the depth of observation is quite limited. The equipment can be operated with much longer sweeps if desired, although this is rarely done. At Columbia gas well No. 20403 near Huntington, West Virginia, two wet-hole logs were run with sweeps of about 30 ms (an order of magnitude longer than normal). Part of the record is shown in Fig. 6. The solid-looking straight vertical lines are water waves, boundary waves, etc.; the "hash" beyond them is presumably signal returned from reflectors far from the borehole. We hope to extract useful information from this late-time record, or "coda."

The coda is rather difficult to interpret as it stands. Therefore it was digitized on a microdensitometer. Unfortunately, the digitization had to be performed piecemeal, and the result was a record of film density vs position on the film, corresponding to signal amplitude vs depth and time. These records were input to a contour-plotting computer program, and two film-density contours were plotted for each section of record (Fig. 7). The contours were then redigitized with a hand-tracing type digitizer so that a new continuous record of a contour for the entire hole could be plotted. The result is shown in Fig. 8. Also shown in Fig. 8 are two logs (a sibilation log and a "fracture intensity log"), which are indicative of gas entering the borehole. Peaks in these logs seem to be associated with dips in the contour log. These dips indicate that a signal of a given intensity dies away sooner at that depth than at depths nearby; thus, the signal at that depth is weaker.

An explanation of why such a dip might be associated with a gas show has been suggested by R. C. Carlson of LLL. Assume that the signals seen in Fig. 6 have been scattered many times from fractures before arriving at the detector. If there are very few scatterers (fractures), no signal will be returned to the detector. This situation obtains in the top part of Fig. 6. If there are very many scatterers, the scattered signal will be greatly attenuated, and there will be very little signal at the detector. With an optimum number of scatterers, the signal will be largest. The dips in the contour, then, indicate a situation in which the signal has been greatly attenuated. This would suggest that there are many fractures and therefore recoverable gas.

Figure 9 compares the logs in Fig. 8 with a number of others in the same hole. Of them, only the acoustic-amplitude and the 3-D logs (run with a transmitter/receiver spacing of 30 cm) seem to show anomalies not associated with lithology. In both logs, the gas shows at 3100 ft and 3800 ft are associated with anomalies. The 3-D log suggests that a fractured region begins at 3100 ft and ends at 3800 ft. The amplitude log shows a low-amplitude region there, which indicates fracturing, but there is nothing on these logs to indicate the individual gas shown. Therefore, the log-sweep acoustic log seems to be the most promising one currently available.

Eric Smith of Columbia Gas Company has shown that peaks on a natural gamma-ray log are associated with the presence of kerogen in Devonian shale. A number of samples from Columbia Gas well No. 20403 near Huntington, West Virginia, were analyzed with gamma-ray spectroscopy. David Coles of LLL performed the analysis. Four of the samples were light in color, presumably low in kerogen, and four were dark, presumably because of high kerogen content. A high gamma count was found associated with the dark samples.

David Coles of LLL also analyzed for gamma-rays due to ^{40}K and the chains of ^{232}Th, ^{238}U, and ^{235}U. He used a Ge(Li) detector, which sees each gamma peak in detail, and came out with a table of disintegrations per minute for each of the four nuclides of interest. The table does not explain the gamma-ray log of well No. 20403 by itself, and so it is not reproduced here.

The gamma-ray log in that hole was evidently performed with a Geiger-Muller counter, which does not discriminate between the gamma rays. The ^{232}U chain produces eight. When Coles' results are multiplied by these factors, the result clearly explains the log. Figure 10 shows the gamma-ray log in well No. 20403, with Coles' data, multiplied as above, properly scaled, and with the two uranium chains added. It is obvious that the majority of the count-rate difference is caused by the uranium.

Table 1 shows a geologist's description of the cores at each depth point. The high-count points are also the darkest in color. Looking at the powdered samples, the color difference is very clear between the dark samples at 2740, 3055, 3220, and 3720 and the other four.

We may safely conclude that the difference in count rate between the dark and light samples is caused by isotopes of uranium. Cole has written a paper that shows that coal is similarly enriched in uranium.[7] This paper may explain why the uranium is present in the kerogen.

MECHANICAL MEASUREMENTS OF DEVONIAN SHALE

Prediction of fracture intensity, geometry, and extent resulting from high-explosive or hydraulic-fracturing stimulation of a low-permeability, gas-bearing formation requires certain equation of state (EOS) or mechanical measurements as input to the calculational codes. These measurements include: tensile strength, failure envelope (under pressure), loading moduli, loading path (up to the failure envelope), and pressure/volume behavior.

To characterize the mechanical behavior of the 10-cm core from Columbia gas well No. 20403, we elected to subdivide it into four distinct units. These were:

Upper gray member	807-1039 m
brown gaseous member	1039-1116 m
white slate member	1116-1203 m
Marcellos black shale member	1203-1233 m

Each of these units was then treated as an individual rock for the purposes of defining an EOS. For each unit, we have planned to determine:

1. The tensile strength parallel and perpendicular to bedding, 0.1 MPa.

2. The uniaxial stress failure envelope in compression to $\sim$ 300 MPa confining pressure, parallel and perpendicular to bedding.

3. The uniaxial stress failure envelope in extension to 400-600 MPa confining pressure, parallel and perpendicular to bedding.

4. The pressure/volume behavior to 1.5 GPa.

5. The loading path in uniaxial strain (compression) beginning at 0.1 and 50 MPa confining pressure. Loading direction both parallel and perpendicular to bedding.

6. The shear and compressional wave velocities to confining pressures of 1.0 GPa (measurements made both parallel and perpendicular to bedding for the determination of dynamic elastic constants).

During this past year, we have determined all eight sets of measurements under item 1 above (two directions in each of four rock units). These are summarized in Table 2. In general, there does not appear to be any discernible trend in strength with either depth or between rock units (for the same orientation). The tensile strength parallel to the bedding seems to be about two times that measured normal to bedding.

We have also completed all measurements outlined in item 2. Typical results are illustrated in Figs. 11-14. In each figure, the compression failure envelope for the virgin shale is defined by the points. At low-moderate pressures, the failure mode is termed brittle in all cases and is the result of combined tensile and shear fracture. The former dominates at low pressure and is oriented parallel to the maximum principal stress σ_1. However, the latter becomes dominant at moderate-high pressures and is oriented at $\sim 30°$ to σ_1. At the highest pressures tested, these shale units frequently become ductile, that is, all deformation is quasi-uniformally distributed within the test sample. The brittle-ductile (B.D.) transition point usually occurs at lower pressures for loading normal to bedding than for compression parallel to it (Figs. 11 and 12). Also shown in these figures is the post-failure strength envelope, designated by points Δ. This surface delineates the shear strength of the fractured shale vs confining pressure. At the brittle-ductile transition, there is no strength decrease upon failure, only distributed flow, and hence, the two curves become identical at higher pressures (Figs. 11-14). Comparison between Figs. 11 and 12 suggests that at similar pressures, this shale unit has only about a 10 to 20% strength anisotropy with loading direction. Loading parallel to bedding seems to be strongest (except at the lowest pressure), but more brittle than for perpendicular to bedding.

Determination of the failure envelope in uniaxial stress loading for extension (item 3) has been completed for 5 of the 8 possible combinations (two directions in each of four rock units). Examples of these failure envelopes are illustrated in Figs. 13 and 14 for comparison with the compression curve. At low pressures, this extension envelope always is much lower than that for compression; at high pressure, it may remain lower (Fig. 13) or it may exceed it (Fig. 14).

The pressure/volume behavior (item 4) of units 1 through 3 is summarized to 4.0 GPa in Fig. 15. This figure clearly indicates that the known gaseous shale member is the most compressible (except at low pressure), followed by the Marcellus black shale member, and the white slate member. Volume changes at 210 GPa, for example, are about 9.2%, 8.3% and 6.5%, respectively for the three members. Each curve shown in Fig. 15 is based on the average of 3 or more tests. These results are unaffected by sample orientation.

Also shown in Figs. 11 through 13 are the uniaxial strain loading paths as described in item 5 (above). In each case, regardless of the initial starting pressure, this loading path rapidly becomes sub-parallel to the virgin compression envelope curve at about one-half of that value. Large hysteresis occurs upon unloading (Fig. 11).

Acoustic velocities listed under item 6 have not been completed. These, as well as the remaining work noted above, will be completed in the next quarter.

LABORATORY EXPERIMENTS ON HYDRAULIC FRACTURE

A laboratory experimental program has been established to provide a better understanding of the initiation and growth of a fluid-driven crack. The parameters to be considered are: (1) the mechanical properties of the solid, i.e., elastic moduli, strength, etc., (2) the physical state of the solid, i.e., presence of pre-existing cracks, porosity, layering, etc., (3) the boundary conditions, such as free surfaces, applied overburden stresses, etc., and (4) the manner in which the crack-driving fluid is injected into the solid.

The overall goal of this research is to explain how these parameters determine the details of crack growth such as direction, orientation with respect to fluid injection hole, growth rate, and forking or dividing. We also seek an understanding of how a crack behaves in the region near an interface, both in a single material and between two materials having dif different properties. Clearly, laboratory-scale experiments cannot simulate all conditions encountered in an actual in-situ hydraulic fracture experiment. However, it is felt that the understanding gained will definitely be useful in the design of large-scale fracture operations.

We have begun by investigating experimental techniques of generating hydraulic fractures and controlling and observing their growth. A few experiments have been performed on rocks, but for the majority, we have used polymethylmethacrylate (PMMA) as the fracture medium. Its transparency permits easy observation of interior cracks.

The technique used to induce hydraulic fractures in all experiments so far has been to inject pressurized oil into the sample through a borehole cased with a steel injection tube. A short, uncased, smaller-diameter portion of the borehole is located at the bottom of the injection tube so that the injection tube rests on a shoulder as shown in Fig. 16. The steel injection tube (0.250 in. O.D.) is slightly smaller in diameter than the borehole

(0.280 in. I.D.) and is secured in the borehole by a mixture of Hysol epoxy. To give a definite direction to the work, we sometimes use a special tool to make a small pre-crack in the open portion of the borehole below the injection tube. The dashed line in Fig. 16 denotes such a pre-crack. This technique has been used so far only in PMMA fracture experiments. In each experiment, prior to connecting the injection tube to the hydraulic pressure line, we fill the injection tube and borehole section with hydraulic fluid so that all air is displaced. Pressure is applied with a hand-operated pump.

Early in the program, a series of experiments were performed to assess the relative fracturability of several rock types to be used in future experiments. The test samples were generally cylinders 2 to 5 in. in diameter and 6 to 12 in. in height. The rocks chosen were Indiana limestone (porosity about 15%), Nugget sandstone (porosity about 5%) and three types of shale. Fluid injection holes were fabricated along the cylinder axis as described above. The Indiana limestone and Nugget sandstone were found to be the strongest of the rocks tested. They fractured in the 5000 to 6000 psi injection-fluid pressure range. The planes of these fractures were parallel to the borehole as shown in Fig. 17. The shales were found to be much weaker, fracturing in the 1200 to 1600 psi injection-fluid pressure range. The shale fractures were in the bedding planes, which in these experiments were perpendicular to the boreholes.

These preliminary experiments in rocks yielded little quantitative data other than the relative fracture strengths of the different rock types. Future experiments are planned to assess the effects of externally applied stress fields and the rate of fluid injection on hydraulic fracture generation.

Experiments to study the effect of an external stress field were performed using PMMA. The test specimens were 4 in. cubes. In the first two experiments, the pre-crack was oriented parallel and perpendicular to the faces upon which a 2000 psi load was applied as shown in Figs. 18a and 18b. In the first case (Fig. 18a), the crack developed from the pre-crack at a borehole pressure of 2500 psi and grew parallel to the applied stress. In the second case (Fig. 18b), a new crack formed at a borehole pressure of 7000 psi and grew parallel to the applied stress. This new crack was independent of the pre-crack. In a second set of two experiments, the pre-crack was oriented at 45° to the cube faces along the diagonal as shown in Figs. 19a and 19b. In one case no external load was applied, and the crack grew as a continuation of the pre-crack at a fluid pressure of 2500 psi as shown by the dashed line in Fig. 19a. In the second experiment, a 2000 psi load was applied. At a 3000 psi borehole pressure a crack grew from the pre-crack but turned and grew parallel to the applied load as shown by the dashed line in Fig. 19b.

To study hydraulically driven crack motion near an interface, a block of PMMA (8 in. x 8 in. x 4 in.) was sectioned into three pieces as shown in Fig. 20. The interfaces I_1 and I_2 were machined flat. Interface I_1 was bonded by a thin film of chloroform. Interface I_2 had no bond. The assembly was loaded with a stress of 2000 psi as shown in Fig. 20. The borehole was pressurized to 3000 psi, where fracture occurred. The fracture did not cross either of the interfaces, but was contained in the shaded area shown in Fig. 20. In a similar experiment in which Indiana limestone was bonded to PMMA with no external applied stress, the crack crossed the interface from PMMA into the limestone. However, when the injection hole was put in the limestone and an attempt was made to drive the crack from limestone into PMMA, the crack would not cross the PMMA-limestone interface.

RESERVOIR ANALYSIS

As part of our study of hydraulic fracturing as a stimulation method, we have performed further evaluations of the nuclear-explosive-stimulated well (RB-E-01) located about one mile from the massive hydraulic fracture experimental well (RB-MHF-3) near Rio Blanco, Colorado. In this experiment, three 30-kt nuclear explosives were emplaced at depths of 5480, 6230, and 6690 ft, respectively. The upper explosive was in the Fort Union formation, while the lower two were in the Mesa Verde formation. These are the same two formations studied in the MHF well.

The explosives were detonated as planned on 17 May 1973. The explosively fractured region was reentered thru the emplacement well and initial production testing commenced in November 1973. The initial drawdown (during which ∿ 35 mmscf of gas were produced) indicated that contrary to original expectations, the production originated only from the chimney volume created by the top explosive, not from the three chimneys combined. Additional production of about 65 mmscf during the first two weeks of February 1974 reduced the chimney pressure to about 450 psi, and there was still no indication of communication with the lower chimneys. (Rare gas tracers had been emplaced with each of the explosives to give a measure of the contribution from each chimney.)

In late 1974, the lowermost chimney was entered by slant drilling from a well (RB-AR-2) offset about a quarter of a mile. Approximately 25 mmscf of gas were produced in December 1974, and this lowered the chimney pressure from an initial 1900 psia to just over 1200 psia. The well was then shut-in to monitor the pressure buildup. An early indication that the well was connected to gas sands of limited extent was the initial pressure of 1900 psia, which was about 1000 psi lower than hydrostatic.

After several months of pressure buildup, an attempt was made (via modeling studies) to evaluate the characteristics of the formation feeding the chimney and the stimulation due to explosive fracturing. We used a computer model, which simulated the chimney, fractures, and formation. The gas-flow calculations were done using the TRUMP computer program.

The basic modeling procedure involved assigning values to the various model parameters (permeability, pay height, permeability enhancement due to fracturing, and chimney size), driving the model with the known production history, and then comparing the calculated chimney pressure history with the measured pressures. After changing the value of one or more of the parameters, the process was repeated over and over until a reasonable match was obtained between the calculated and measured pressure histories.

This early modeling led to a pair of models that appeared to bracket the somewhat scattered data. These models used permeabilities of 5 and 10 μd, respectively, and a pay height of 50 ft. The radial extent of the models was effectively infinite. With the passing of time, the effect of finite lens size became evident as the calculated pressures continued to rise while the observed buildup essentially stopped. Further modeling directed at a study of the lens size led to the conclusion that a 10-μd permeability and a 50-ft pay height, with an effective outer boundary radius of womewhat under 400 ft would fit the data reasonably well. However, the observation that the pressure history could be interpreted as showing a slight late-time decline (within the scatter of the data) prompted a reconsideration of the model.

It was recognized that the chimney, initially at a temperature of perhaps 600°F, would be very slowly cooling; however the low rate, on the order of 0.1°F/day, would be only a small perturbation as far as the change in gas density was concerned. It was then realized that the vapor pressure of water (which contributes to the total pressure in the chimney) changes many times more rapidly in this temperature range than does the absolute temperature. A thermal model of the chimney and surrounding rock was constructed to obtain an approximate thermal history of the chimney. This model indicated that during the 600 days following the start of buildup the chimney temperature declined only 40°F (from 500°F to 460°F), while the vapor pressure of water dropped 300 psi (from 700 to 400 psia).

Further work led to a model with a formation permeability of 10 μd, a pay height of 60 ft, and an effective lens radius of 450 ft. The calculated and measured pressure-vs-time histories are shown in Fig. 21. Figure 22 shows the fracture-induced permeability used in the model.

GEOLOGIC STUDIES FOR GAS STIMULATION MODELS

Realistic models for the stimulation of gas from the Devonian brown shale of the Appalachian Basin and the low-permeability western gas sandstone require a careful consideration of the geology of each reservoir. In contrast to the tight sandstone, the shale has a lower gas-filled porosity, (about 2% versus 5%) a lower reservoir pressure (they are shallower and have less-than-normal pressure gradients), and a very low gas permeability (less than 1 μd vs about 2 μd). However, the reservoirs are thick (about 400 ft) and extensive (55,000 to 110,000 square miles).

The Western sandstone formations are considerably more variable. Not only do they show a wider range of physical properties, they are geometrically variable. Figure 23 shows the geographical distribution of basins with low-permeability sandstone reservoirs. Areas like the Denver Basin have predominantly thin, but extensive marine margin sandstone deposits that are amenable to stimulation by long fractures. A few units of this type exist near the basin of the Mesa Verde formation in the Piceance and Uinta Basins. However, most of the reservoirs in these latter basins are flurial and lacustrine deposits, elongated lenses within shale. The stimulation technique and analysis must take the spatial variations of these continental deposits into consideration. A typical channel-fill deposit in the Piceance Basin Mesa Verde formation is 25 ft thick, 350 ft wide, and 3,500 ft long. Clearly, a fracture generated across the width need not exceed 350 ft in length. To be effective, a single well should be completed by stimulating each sand zone according to its own characteristics. Detailed studies of typical basins are now underway to provide the necessary information for an understanding of local variations and their effect on stimulation methods.

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FIGURE CAPTIONS

FIGURE 1. Dilatation contours around a pressure-opened fracture at $\tau = 0.44$, where $\tau = \frac{k}{\mu(\alpha+\eta\ \beta)} \frac{t}{L^2}$; k is the permeability of the medium, μ is the viscosity of the injected fluid, α is the compressibility of the elastic matrix, η is the porosity, β is the compressibility of the injected fluid, t is the problem time, and L is the length of the fracture.

FIGURE 2. Dilatation contours around a pressurized fracture at $\tau = 4.138$. See Fig. 1 for a definition of the nondimensional time τ.

FIGURE 3. Representation of a vertical hydrofracture in a layered medium. Vertical displacements of the surface are shown at the top of the figure.

FIGURE 4. Distortional contours for the problem geometry shown in Fig. 3. Distortion is defined as $|\varepsilon_1-\varepsilon_2|$ where ε_1 and ε_2 are the principal strains.

FIGURE 5. Illustration of typical intensity-modulated, continuous-velocity (3-D) log.

FIGURE 6. Part of long sweep logging record for Columbia gas well No. 20403 (signal is for 3690 ft to 3960 ft).

FIGURE 7. Initial contours for a segmented, digitized, sonic-logging record for Columbia gas well No. 20403.

FIGURE 8. Composite of processed sonic logging record with two other logs (the sibilation log and a fracture intensity log), which indicate gas entering the borehole.

FIGURE 9. Composite borehole geophysical logs for Columbia gas well No. 20403.

FIGURE 10. Gamma ray log for Columbia gas well No. 20403, properly scaled showing ^{40}K, ^{232}Th and ^{238}U.

FIGURE 11. Failure envelopes for core from Marcellus black shale section for Columbia gas well No. 20403. Samples tested were perpendicular to bedding.

FIGURE 12. Failure envelopes for core from Marcellus black shale section for Columbia gas well No. 20403. Samples tested were parallel to bedding.

FIGURE 13. Failure envelopes for core from brown gaseous shale section for Columbia gas well No. 20403. Samples were perpendicular to bedding.

FIGURE 14. Failure envelopes for core from white shale section for Columbia gas well No. 20403. Samples were perpendicular to bedding.

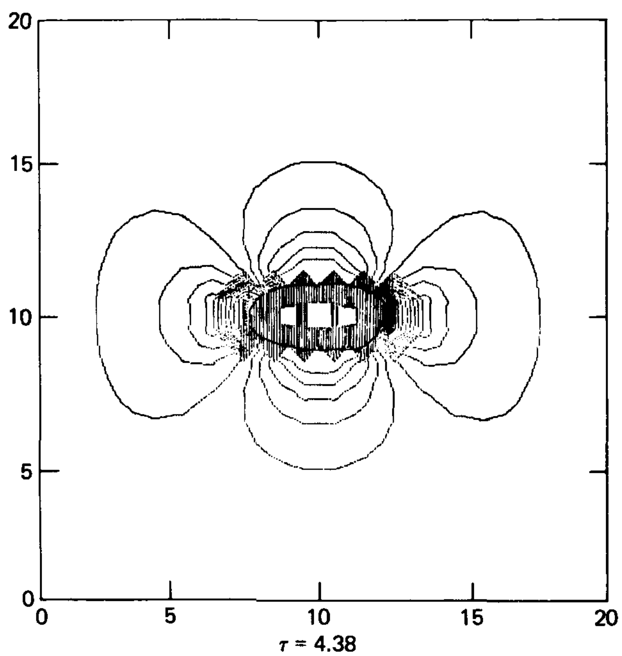
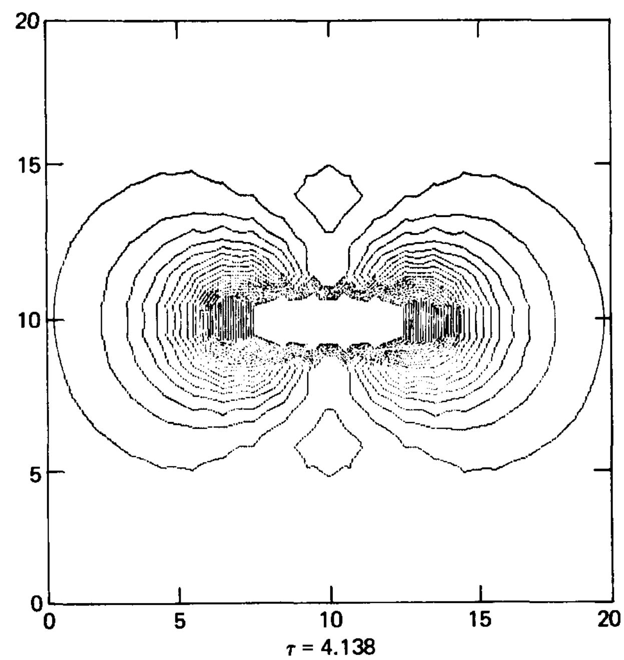


FIGURE 1



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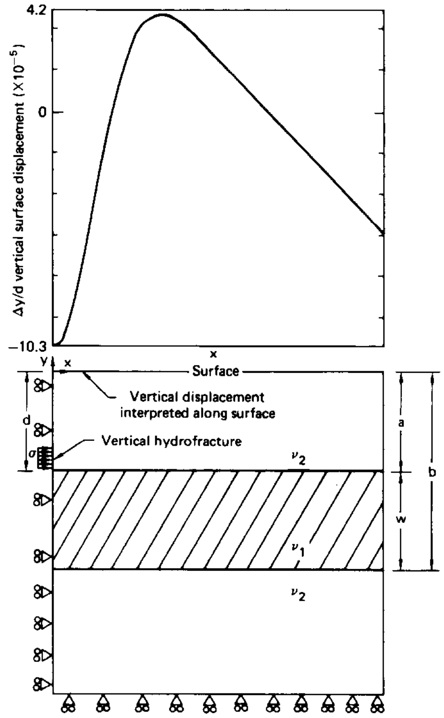

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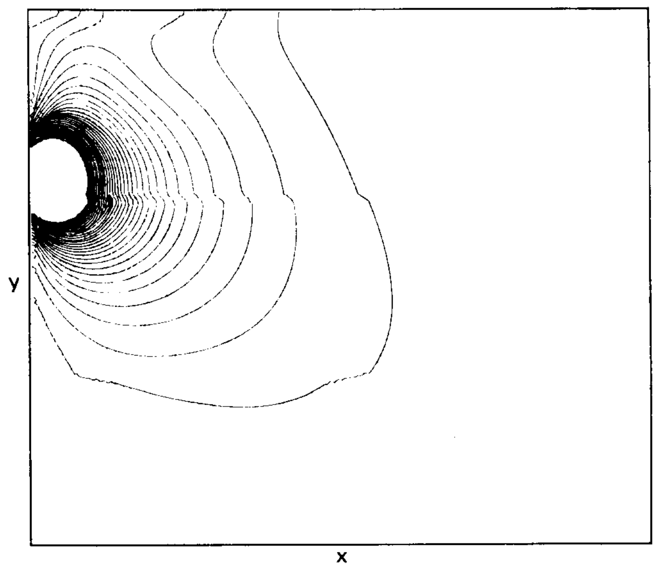
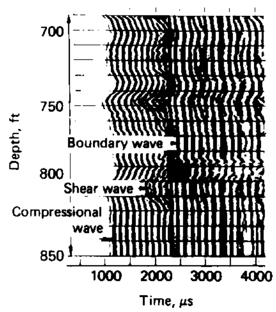


FIGURE 4



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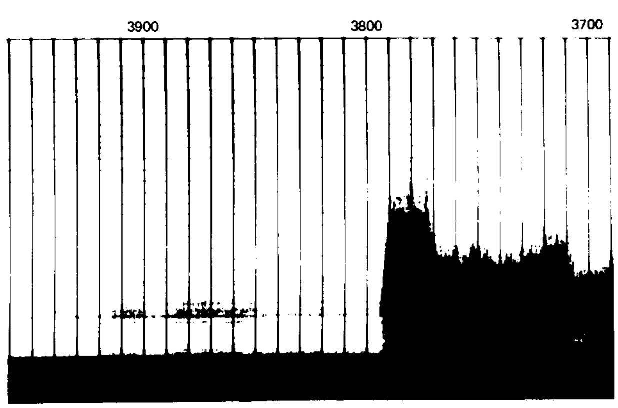

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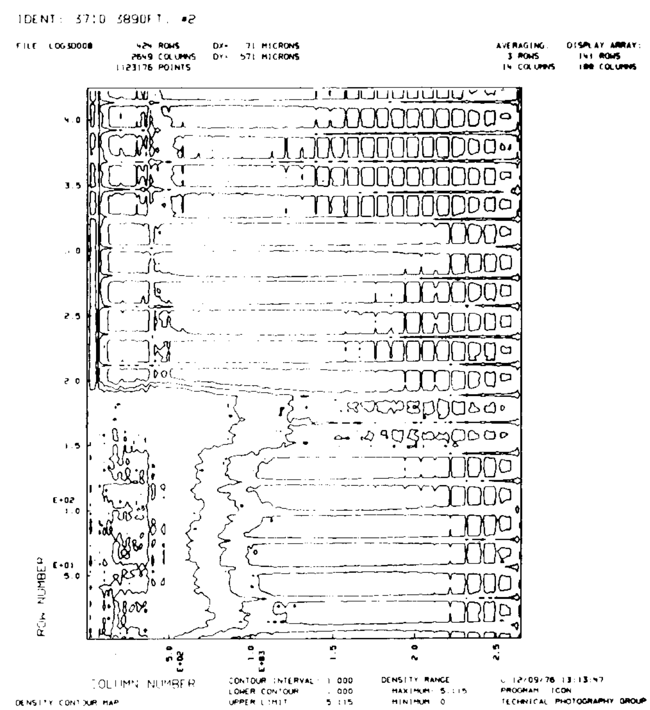

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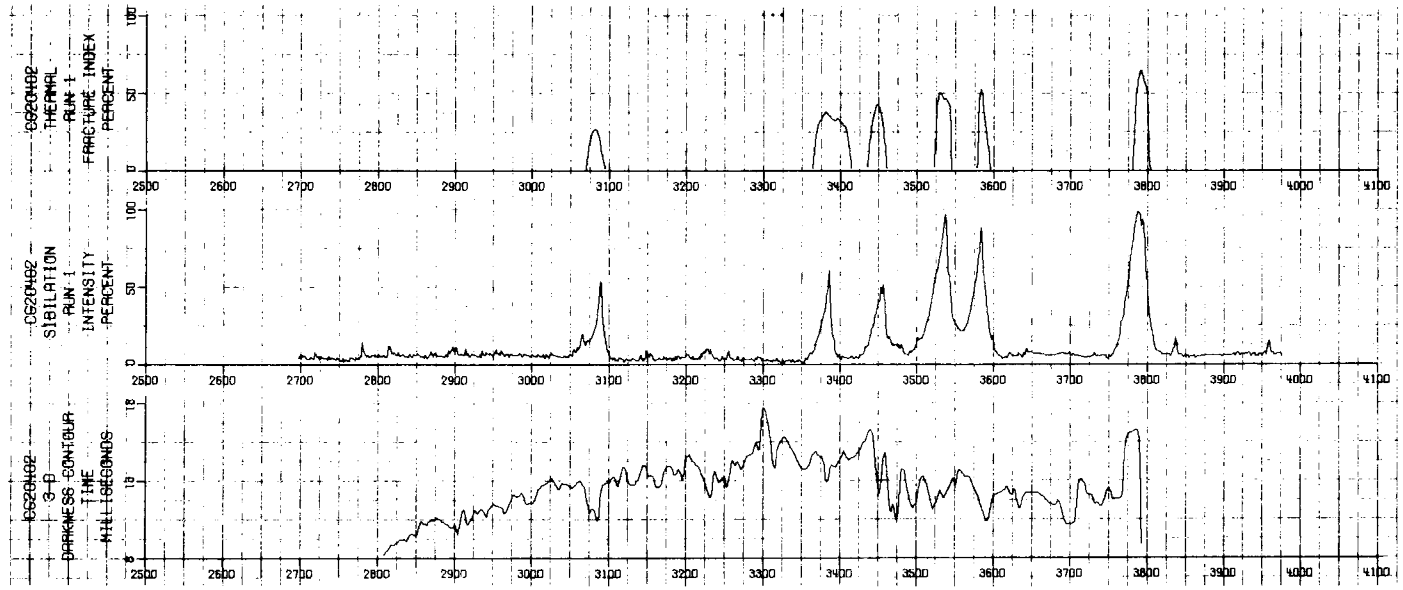

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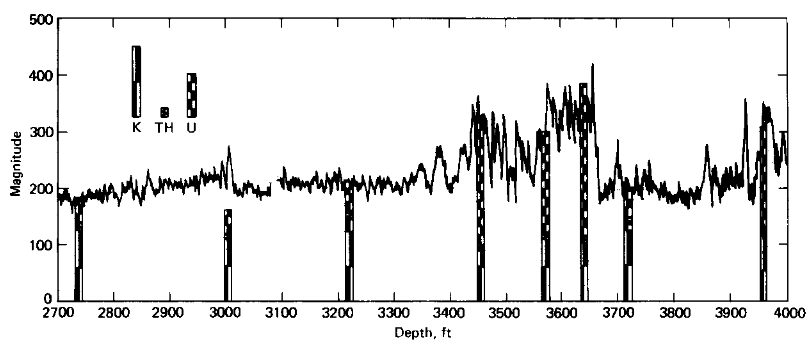

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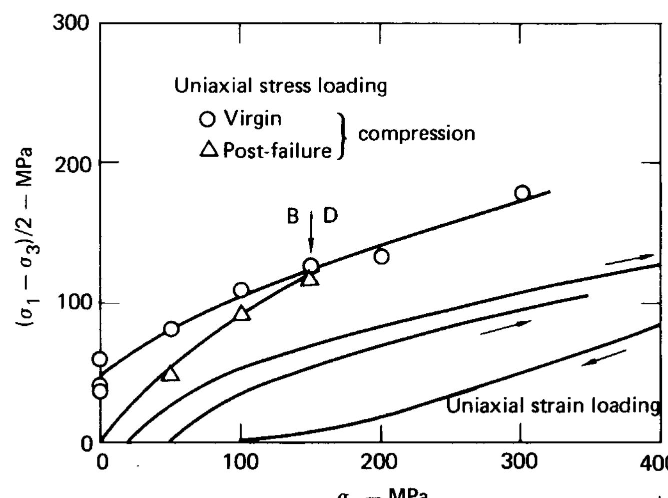
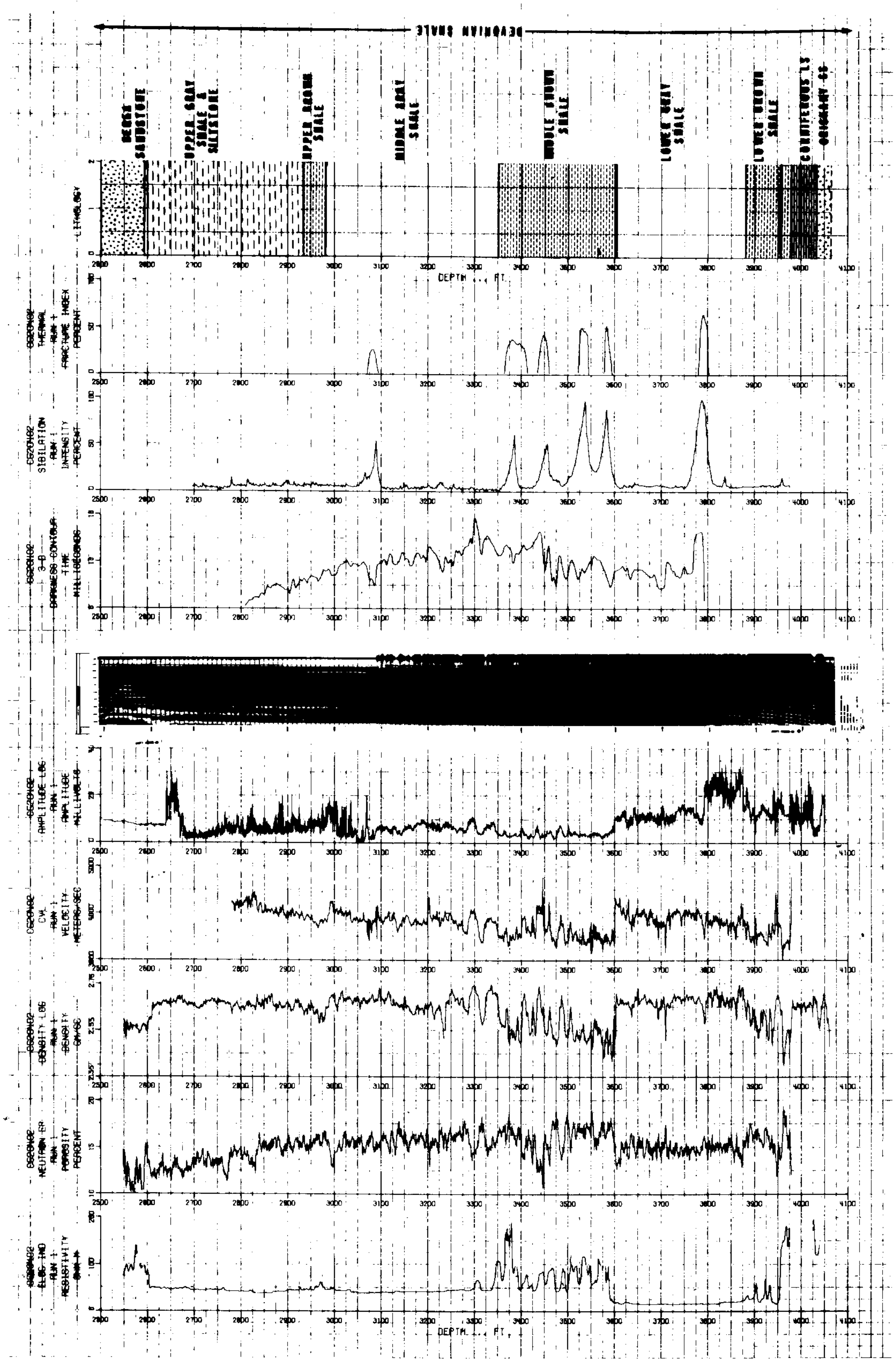


FIGURE 11


DEVONIAN SHALE
BEREA SANDSTONE
UPPER GRAY SHALE & SILTSTONE
UPPER BROWN SHALE
MIDDLE GRAY SHALE
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ORISKANY SS
LITHOLOGY
DEPTH ... FT.

FIGURE 9

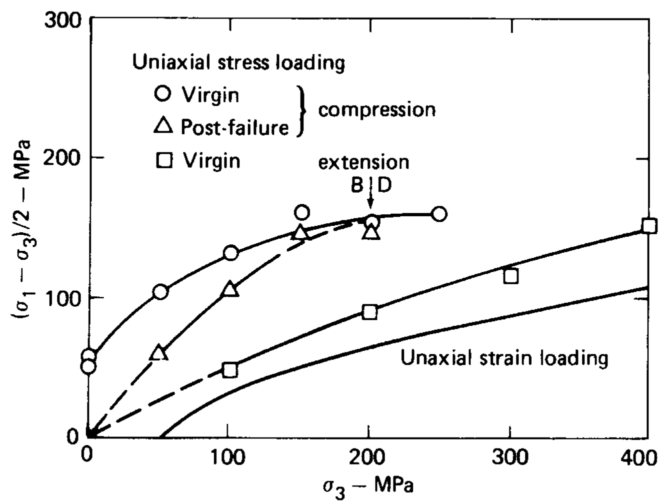
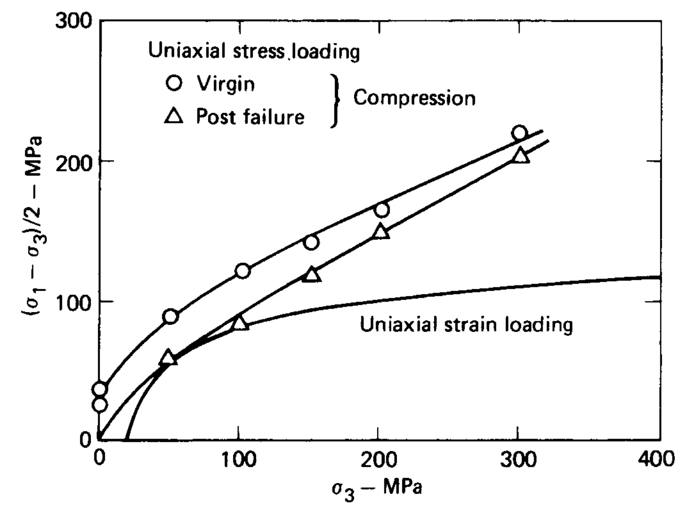


FIGURE 12



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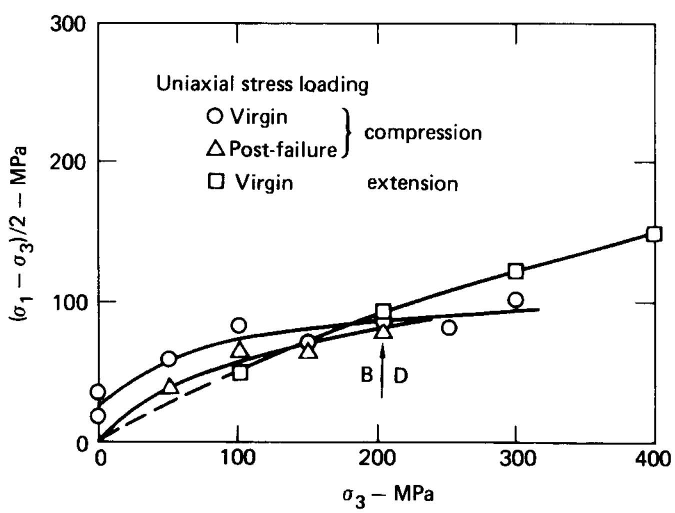
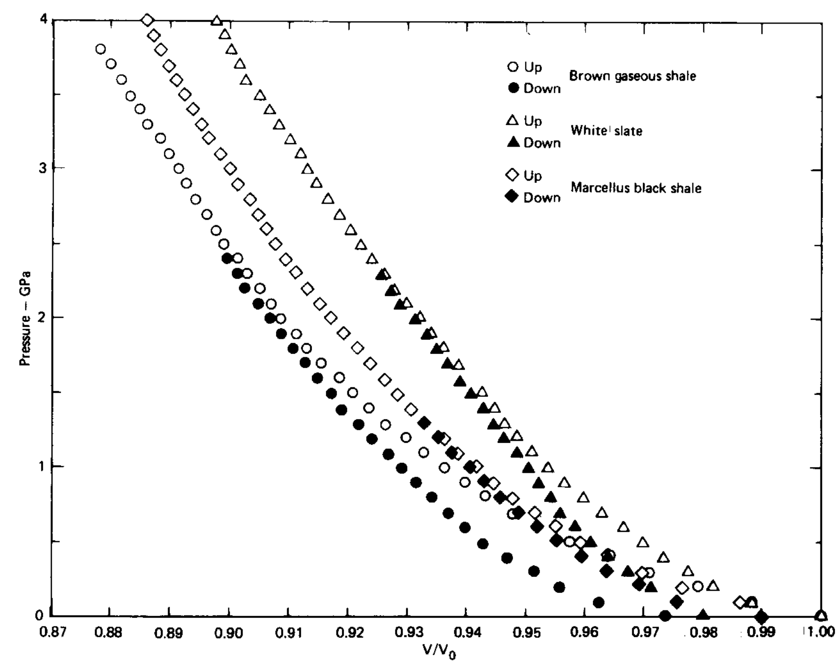


FIGURE 14



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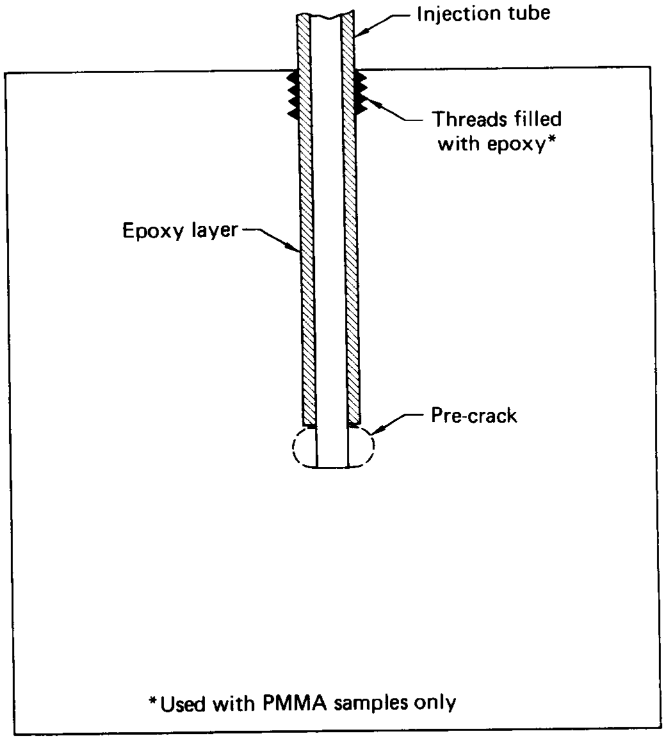

FIGURE 16

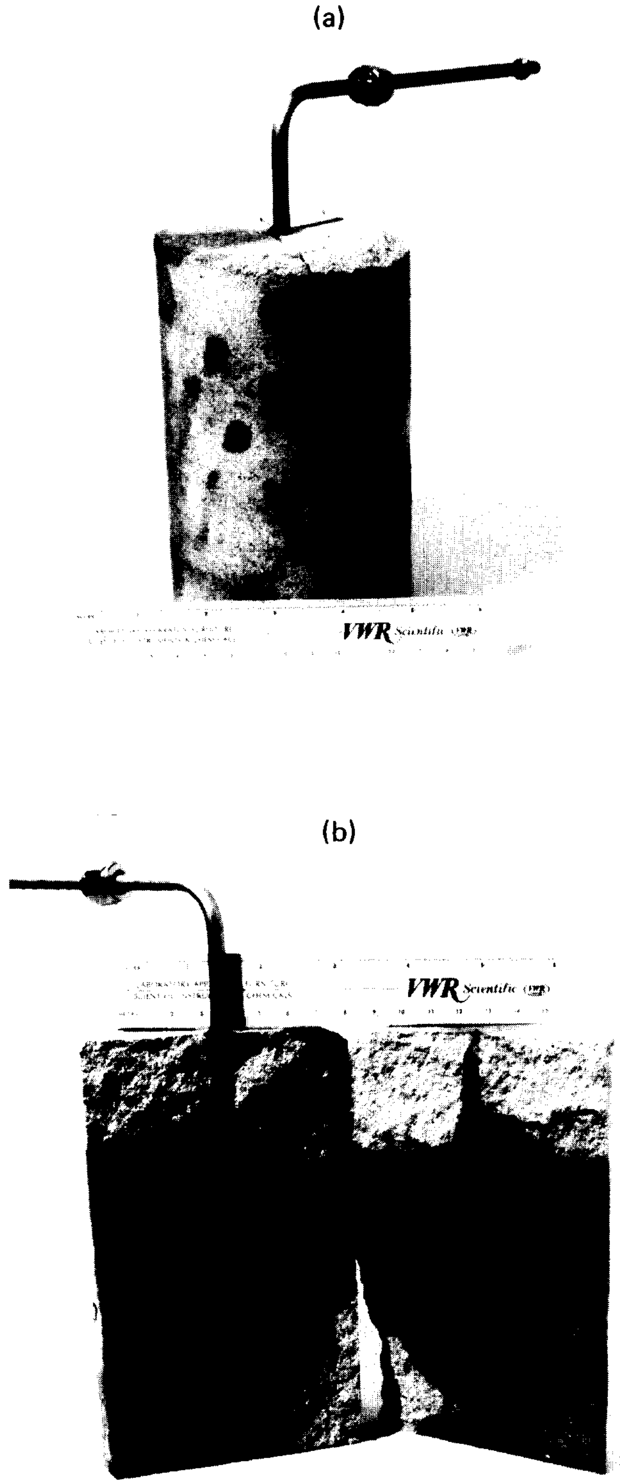

FIGURE 17

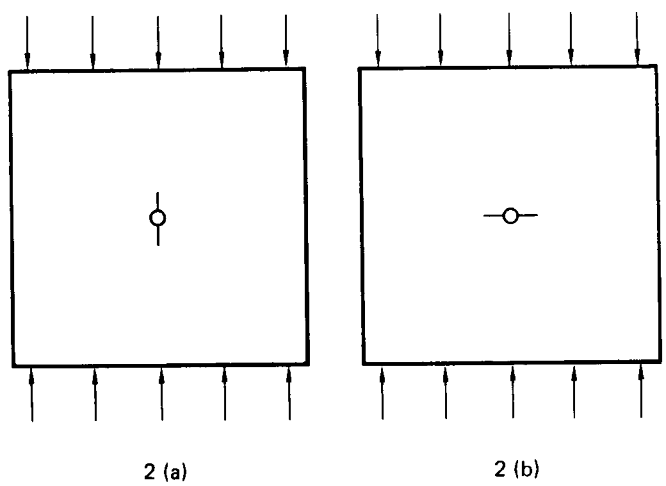

FIGURE 18

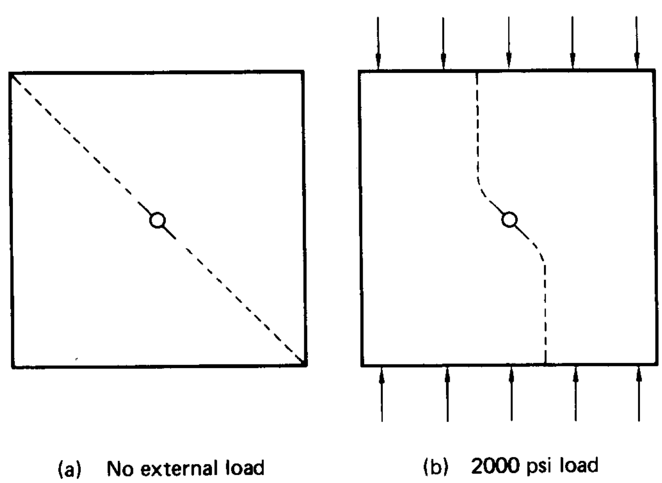

FIGURE 19

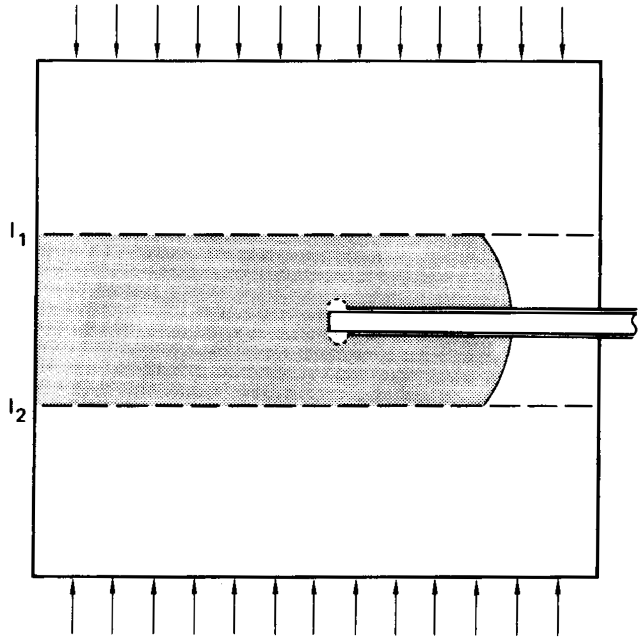

FIGURE 20

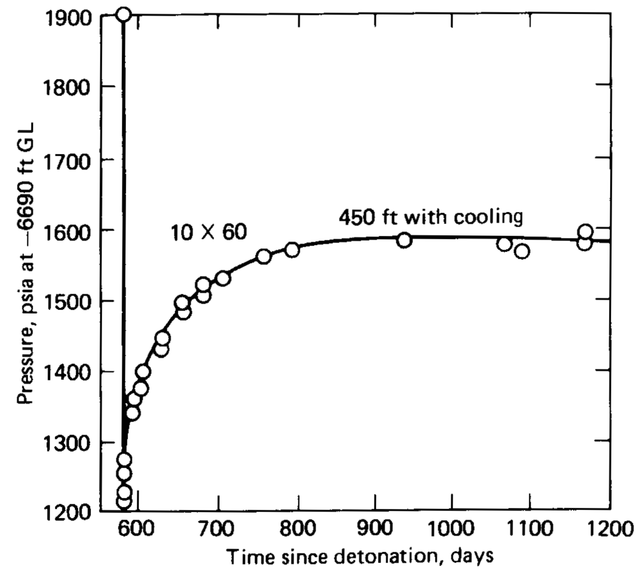

FIGURE 21

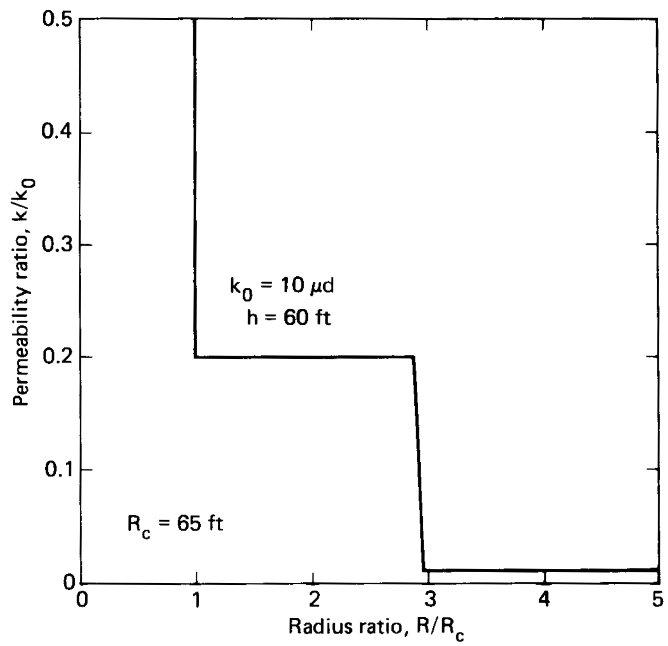

FIGURE 22

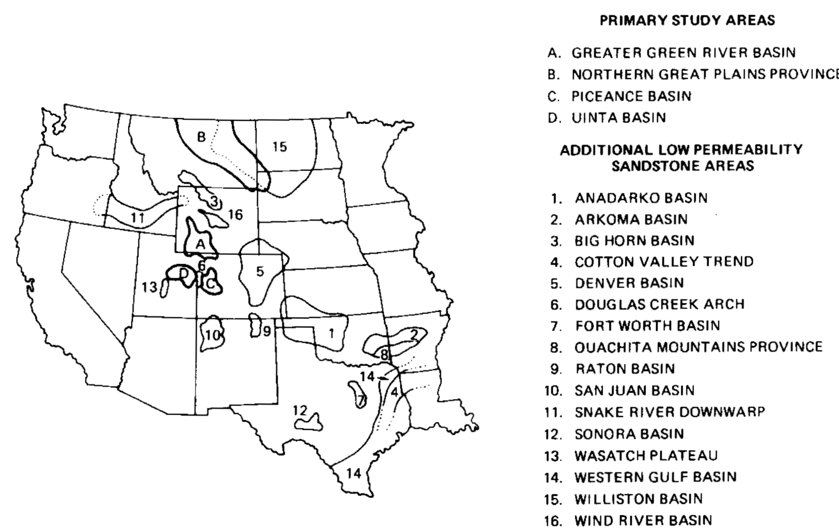

FIGURE 23

IN SITU EXAMINATION OF HYDRAULIC FRACTURES*

by

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Albuquerque, New Mexico 87115

ABSTRACT

Hydraulic fracture experiments have been performed in Rainier Mesa at ERDA's Nevada Test Site as part of a nuclear containment study. An expanded program to understand hydraulic fractures as part of ERDA's Enhanced Gas Recovery Program is underway. Three fracture experiments conducted to date and plans for this mineback test project will be discussed.

The fracture experiments were performed in a 4-in diameter uncased hole at a nominal depth of 1400 ft in a uniform ash-fall tuff formation. Two experiments were conducted in one hole with different colored grout. The results showed the strong influence of in situ stress on fracture direction and orientation. The third experiment used a water gel frac fluid which was designed to place 20-40 sand, injected in three stages with different concentration and color, uniformly in the fracture. The resulting fracture system was very complex. The effects of faults and bedding planes on blocking fracture growth and changing fracture orientation were pronounced. Data collection and analysis have not been completed, but valuable insight into in situ fracture behavior has been obtained.

Further experiments are planned as part of this project to understand hydraulic fracturing. Direct fracture observation by mineback and correlation with geologic and material properties, fluid behavior, and fracture parameters will form a bridge between modeling and laboratory studies and empirical field production results.

INTRODUCTION

Hydraulic, explosive, and nuclear fracturing stimulation techniques have been applied to low permeability natural gas reservoirs with varying, but generally noneconomic, results. Massive hydraulic fracturing (MHF) as being practiced is based on extensive, "conventional" fracturing experience, laboratory experimentation, and empirical design models; the extrapolation to the massive scale has not been generally successful. Industry has stated the need to perform experiments in an environment which allows for direct fracture examination and evaluation. ERDA's Nevada Test Site provides this opportunity. An existing tunnel complex and support facilities of the Site have been used for the direct examination of hydraulic fractures. These mineback experiments form the basis of a new project aimed at the understanding of complex fracturing processes.

* This work was supported by the United States Energy Research and Development Administration, ERDA, Under Contract No. AT(29-1)789.

This paper is divided into two parts. The first part, In Situ Mineback Experimental Results, presents the results of the mineback hydraulic fracturing experiment performed at the Nevada Test Site. The second part, Mineback Test Project, outlines the role of Sandia's project in the gas stimulation work done by industry.

IN SITU MINEBACK EXPERIMENTAL RESULTS

Since 1974 Sandia Laboratories has had an active research program in hydraulic fracturing. Our initial motivation for the research came from the underground nuclear test program, where our concern was how a leak might occur due to hydrofracing by a condensible fluid. The objectives of the fracturing program were to establish small-scale hydraulic fracture experiments as an in situ stress tool and study the behavior of hydraulically formed cracks in an in situ environment. This work was done in the G Tunnel Complex of Rainer Mesa at ERDA's Nevada Test Site. All the experiments were conducted adjacent to the tunnel so that the fracture data could be collected during a mining operation. The first objective related to in situ stress measurements has been met and hydraulic fracturing is routinely used to measure in situ stresses in the tunnel with a low volume, high pressure pumping system. The aims of the second objective have been expanded to include requirements for hydraulic fracturing research to support ERDA's Enhanced Gas Recovery Program.

Three hydraulic fracture experiments are described below. All of the experiments were conducted in 4-in diameter uncased holes at a nominal depth of 1400 ft. Two experiments were conducted in Hole U12g10.3 using colored grouts as a fracture fluid. The third experiment was done in Hole U12g10.5 using a water based gel as a fracture fluid.

Hole U12g10.3. Two hydraulic fracture experiments were conducted in this hole at different depths. The bottom fracture used a red grout fracture fluid at a bottom hole depth of 1395 feet. After the first experiment was accomplished, a grout plug was poured and the second experiment was done with a yellow grout at a depth of 1365 feet. The fracture interval in the hole for both experiments was 10 feet with a bridge plug set at the top of the interval. Formation breakdown was done by initially injecting 200 gallons of water. This was followed by 272 gallons of grout with water to flush the system. The total volume injected was 700 gallons. The average treatment rate was 3.2 barrels per minute. Flow rate and surface injection pressure were only measured.

The formation rock for these experiments was a uniform ash-fall tuff which has the properties listed in Table I. The mineback investigation showed that both fractures were almost vertical with a dip that varied between 83° and 87° NW. The fractures were also planar in that the bearing for the yellow fracture was N 53° E for 20 feet of recovery and the red fracture bearing varied from N 47° E to N 53° E over a distance of 50 feet. No lateral and vertical extents of the fractures have been defined as yet, but a coring program is underway to complete the fracture geometry definition. The dip and bearing directions of the two fractures correspond to the minimum horizontal principal stress direction. The calculated down hole shut-in pressures compared well with those measured by small hydraulic fracture in situ stress tests done in the tunnel complex.[1] The tunnel tests gave 894 psi for the minimum principal stress with a value of 1065 psi for the Hole 12g10.3 fractures. The dip and bearings found for the small test agreed well with the two grouted fractures.

Hole U12g10.5. A single fracture experiment was done in this hole. The purpose of this experiment was to try to gain some information on the fracture fluid motion during the fracture creation and to get some data on fracture width. The experiment was done in the ash-fall tuff rock described in Table I. The fracture design called for a water based gel (PWG/FR2GL) with colored 20-40 sand of different concentrations to be phased into the fracture schedule at an injection rate of 4 barrels/minute. The design schedule is given in Table II. Flow rate and surface pressures were measured. An annulus pressure was measured to help determine the down hole values.

The mineback evaluation of the experiment has not been completed, but some very interesting results have been obtained. The hole drilled for this experiment penetrated a region of the formation between two faults which strongly influenced the fracture growth and orientation. The faults had small displacements of the order of an inch and contained a rubble zone which was about an inch wide. The formation also had a number of thin bedding planes in the experimental area. The effect of these features on fracture geometry are presented below.

The plan view shown in Figure 1 shows the outline of the tunnel excavated for fracture examination. The enclosed area shown at the bottom of the figure is an excavated bench. The experiment hole is shown at the 55 foot station. The first view of the fracture system is a profile along the line A-A. The A-A view, Figure 2, shows the entire mined fracture system projected on the A-A line. Two fractures were formed. The primary fracture was nearly vertical with a dip varying between 85° NE to 85° NW and essentially lies in the A-A plane except for the tail from CS20 to CS40 which curved out of the plane. The faults and bedding planes are as observed in the A-A plane. The secondary fracture system shown was projected on the A-A plane from the tunnel bench noted in Figure 1. The experiment hole is shown as VDH #5 with the fracture initiation interval being the thin line below the wide line. Two important results about the primary fracture can be seen in this profile. First, the fault to the left of the hole blocked the lateral growth to the north and, secondly, a bedding plane a few feet above the initiation level served as a barrier to vertical growth. The effect of the fault to the right of the hole is shown in later views. Basically, the path of least resistance was downward.

A vertical cross-section, plane D-D, is shown in Figure 3. The primary fracture system is shown passing through the hole and stopping just below the upper bedding plane. The secondary fracture is shown to the left. This fracture has a dip which varies from 10° NE to 80° NE. The marked changes in fracture dip are due to very thin bedding planes. The dashed line at the intersection of the two fractures denotes the absence of sand. Referring to Figure 2, the next view of the fracture system is a plan view of plane E-E. The E-E plane is shown in Figure 4. The fault to the left has retarded the lateral growth, as mentioned earlier, to the north and a new weak fault is evident between the other two faults. The fracture is not connected across the fault to the right in this plane. On the right side of this fault, the fracture begins to change bearing by approximately 40° to the east. Another observation is that the secondary fracture system does not extend to this depth.

From the observations of the placement of the sand and the shape of the fracture system, it appears that the fracture initiated and grew in the downward direction because of barriers due to the fault to the north and the parting plane above. The fault to the south did not stop growth but there is evidence that a marked change of in situ stress exists across the fault because of the direction change of the fracture. Continued exploration of this fracture is planned which includes in situ stress determinations across the faults and bedding planes in addition to further fracture examination.

The above results from the mineback investigation of the hydraulic fracture experiments have demonstrated how different geological features affect fracture growth. In a uniform media, the fractures are vertical with a consistent dip and bearing. When faults or bedding planes are present, the fracture growth may be retarded or reoriented. Additional in situ stress measurements and material property data are being obtained to further quantify the observed fracture behavior in these experiments.

MINEBACK TEST PROJECT

The mineback experiments just presented have been performed as part of a nuclear containment program; their commonality and application to enhanced gas recovery is obvious. An expanded scope of activities is planned for a recently initiated Sandia Laboratories project which is part of ERDA's Enhanced Gas Recovery Program and which is aimed at the understanding of complex fracturing processes. This mineback test project is intended to form a bridge between the design modeling and laboratory studies and the empirical field production results which are the basis for today's fracturing technology.

One view of the role of mineback testing is given in Figure 5. A fracture stimulation as undertaken today is indicated by the upper half of the figure. Industry and service company experience, plus inputs from well logs and other geological information, results in a frac design, the frac job in the field, and a final evaluation. This evaluation is based primarily upon gas production in combination with the operational parameters (fluid type, pumping rate, proppant, etc.) of the job. The evaluation is empirical in nature with the experience contributing to the design of further jobs. Mineback testing offers more information which can contribute directly to production design and practice. As seen in the figure, Sandia would serve as a catalyst in the planning, conduct, and evaluation of a mineback fracture experiment. Evaluation here is accomplished by direct observation of the produced fracture and correlations can be made with the material property, fluid behavior, physical description, and operational parameters as listed. Note that the evaluation feeds back into the same industry-service company experience and knowledge base used in production.

The Mineback Test Project's objective is to understand, and thus improve, fracturing processes for enhanced natural gas production from low-permeability reservoirs. Tasks contributing to this objective are: (1) mineback testing for direct fracture observation and evaluation; (2) rock mechanics, fluid dynamics, and geochemical studies required to interpret observed fracture behavior; (3) incorporation of the results into improved stimulation design models and calculations; (4) assessment and calibration of logging and instrumentation techniques for fracture mapping and characterization; and (5) testing of innovative stimulation techniques.

Industry and service company participation in all aspects of this program is essential. Such industrial interest has been high, and further participation is solicited in this paper. This program will provide a unique opportunity to quantify fracture behavior and is not being done elsewhere.

The trade-offs between number and scale of the experiments and the costs, time and "real estate" consumed by mineback for adequate characterization must be carefully assessed in the test planning. Important experimental areas include: (1) the effects of different fluids, proppants, and pumping schedules upon proppant distribution and fracture conductivity; (2) interaction of the created fracture with naturally-occurring fractures and formation interfaces; (3) the effects of different or novel completion, preforation, and frac techniques upon fracture initiation and propagation; and (4) chemical explosive fracturing. Initial tests would be small-scale, but subsequent larger tests would be conducted to establish scaling parameters appropriate to MHF. Extension of these tests to deep uranium mines which underlie Cretaceous formation of the San Juan Basin is envisioned to provide similar information in a more representative environment.

A formation interface experiment is planned for late summer 1977. Hydraulic fractures will be created above and below an ash-fall tuff-welded tuff interface at a depth of $\sim$ 1350 ft. The two formations have contrasting densities and Young's modulii of 1.77 and 2.19 g/cm^3 and 0.24 and 2.41×10^6 psi for the ash-fall and welded tuffs, respectively.

Supportive rock mechanics, fluid dynamics, and geophysical and geochemical studies will be performed to aid in the interpretation of observed fracture behavior. The mineback experiments will allow for confirmation, in a field environment, of the laboratory and modeling efforts. Formation properties (fracture toughness, spallation, uniaxial and triaxial stress-strain relationships, anisotropy, etc.) will be measured under different conditions of stress, temperature, and water saturation. Fluid dynamics during fracturing involves investigation of frac fluid viscosity as a function of time and temperature, proppant mobility, and fluid loss to the formation. Finally, the resultant permeability for gas flow from the formation to the fracture and along a propped fracture to the well will be investigated and modeled. The geophysical and geochemical effects of the formations on these properties will receive particular attention to make the results applicable to other field environments.

The mineback tests will be used for the assessment and calibration of instrumentation techniques for fracture characterization. Borehole and adjacent-station seismic techniques which map the source of signals generated by the growing fracture appear promising but are known to be complex. Electrical, displacement via tiltmeters, trace, and improved pressure measurements will be investigated. Logging technique--in situ property--observed fracture correlations will be made. Finally, in situ stress measurement technique comparisons will be made in "side-by-side" tests.

CONCLUSIONS

The feasibility of the in situ examination of hydraulic fractures by mineback has been demonstrated. Preliminary results have shown the effects of in situ stress distributions, material properties, and other geologic features upon fracture behavior. An expanded project has been initiated aimed at the understanding of complex fracturing processes by correlating direct fracture observations with laboratory and modeling studies and field production experience. Applications to enhanced gas recovery will be emphasized.

REFERENCES

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TABLE I

ASH-FALL TUFF ROCK PROPERTIES

Bulk Density (gm/cc)	1.77
Grain Density (gm/cc)	2.42
Porosity (%)*	44.6
Modulus of Elasticity (x 10^6 psi)	0.236
Poisson's Ratio	0.312
Bulk Modulus (x 10^6 psi)*	0.211
Shear Modulus (x 10^6 psi)*	0.111
Permeability (millidarcy)**	0.01

* Calculated

** Helium permeability test on 4.75-cm diameter by 5.18-cm long specimens. Test conducted on as-received specimen with zero confining pressure and 300 psi driving pressure. (Our experience shows with small confining pressures the permeability values may be one or two orders of magnitude smaller.)

TABLE II

DESIGN SCHEDULE FOR HOLE U12g10.5

Fracturing Fluid: PWG/FR26L

μ = 79 cp

Schedule: Injection Rate = 4 barrels/minute

Volume		
350 gal	Pad	
450 gal	1 lb/gal	20-40 Sand-Black
400 gal	2 lb/gal	20-40 Sand-Red
400 gal	3 lb/gal	20-40 Sand-Blue
1600 gal	TOTAL	

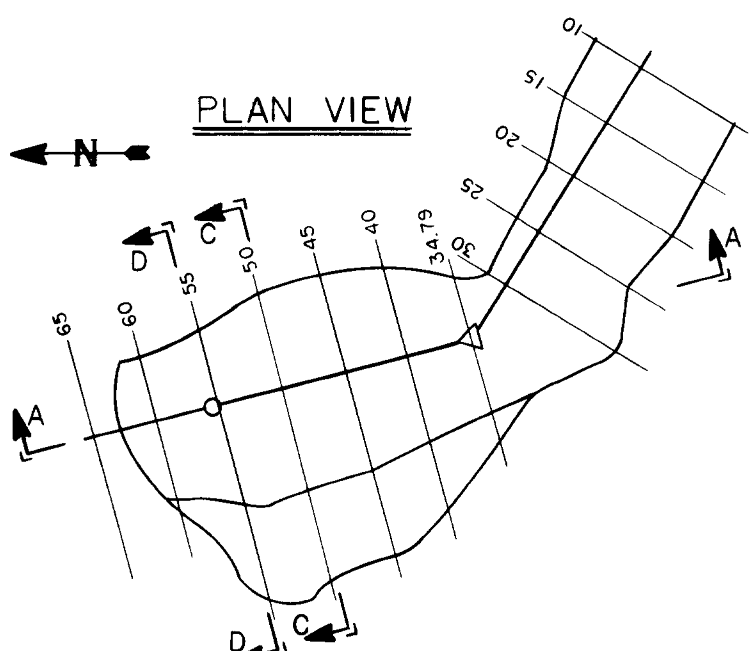


FIGURE I

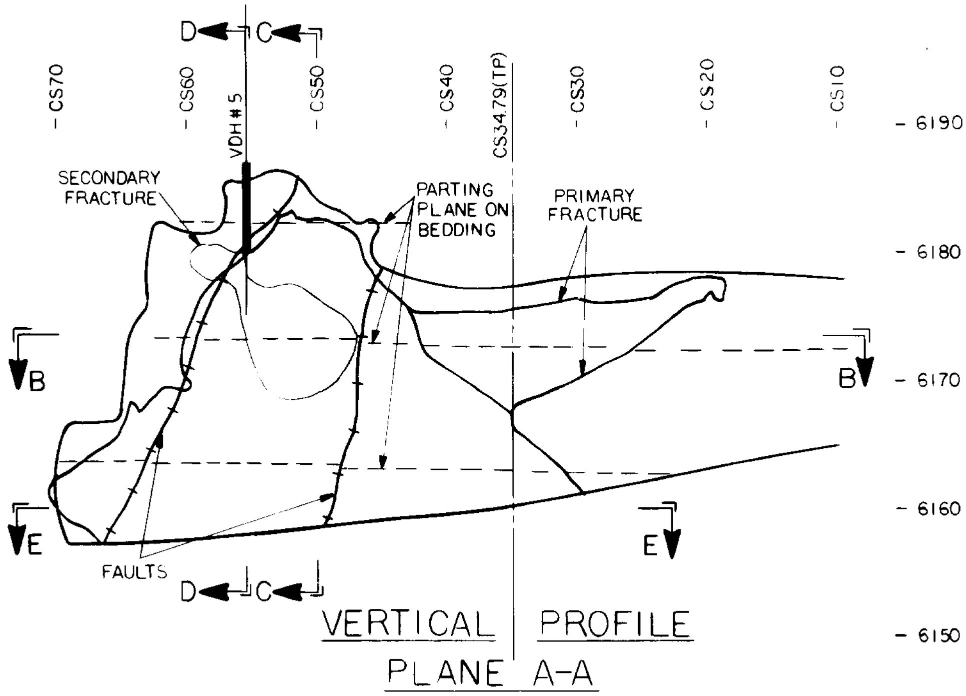
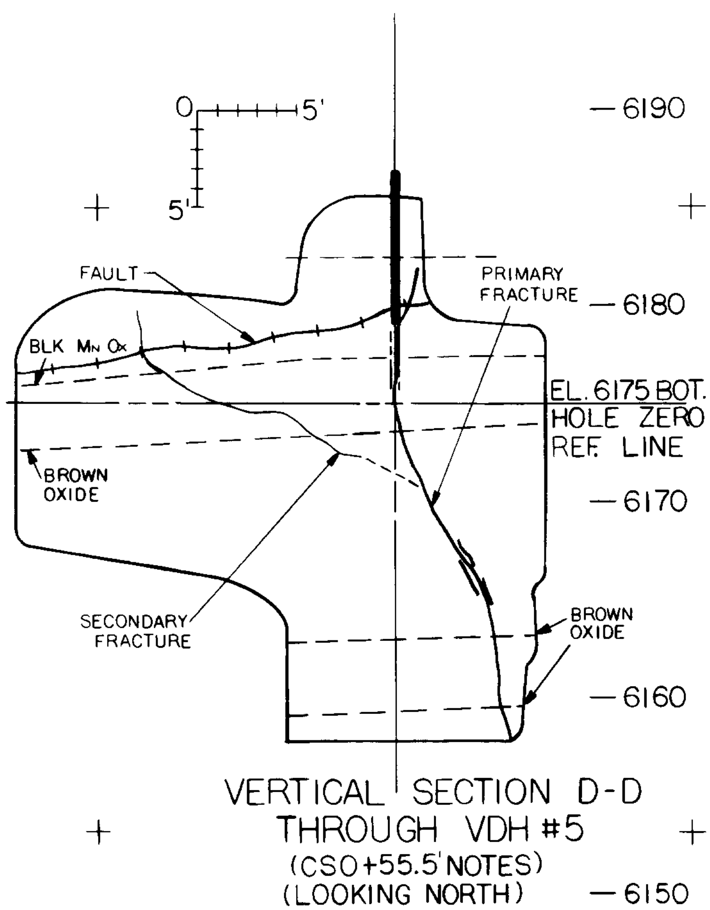


FIGURE 2



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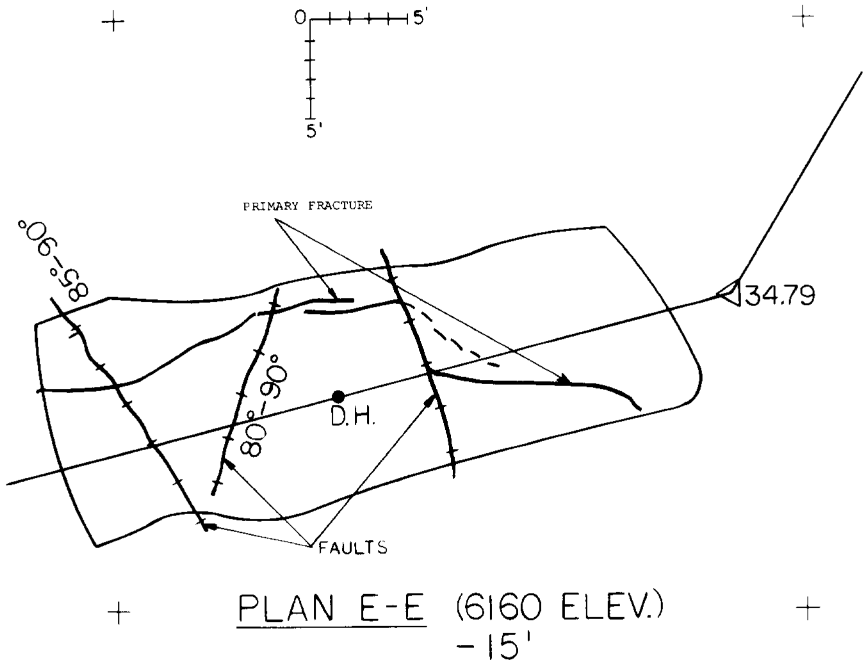

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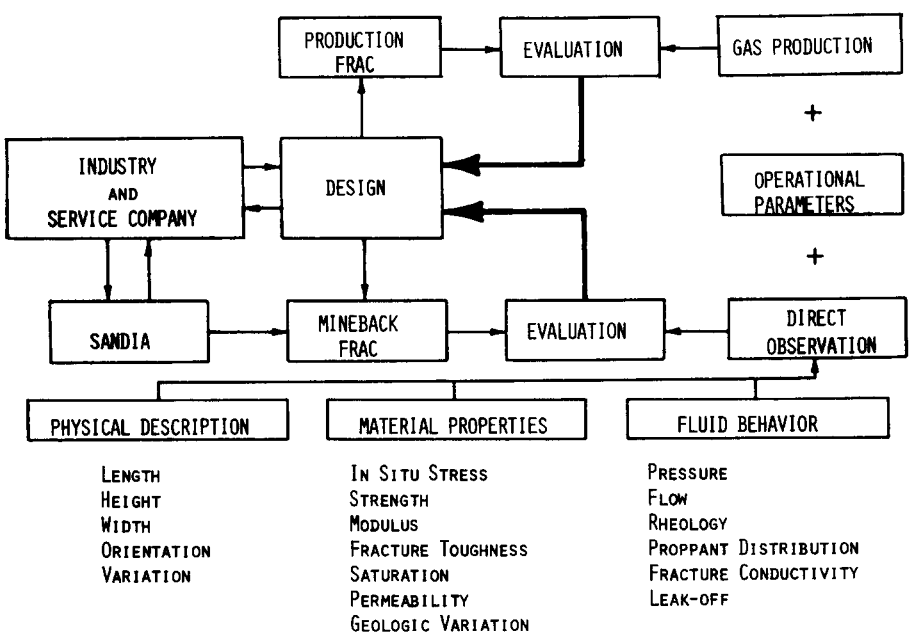

FIGURE 5

A STATUS REPORT ON THE MHF MAPPING AND CHARACTERIZATION PROGRAM*

by

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ABSTRACT

The surface electrical potential system was refurbished and updated during this year prior to conducting several field experiments. Results from these MHF's not only include fracture orientation but also provided some insight into fracture growth periods. A very shallow fracture experiment was also conducted to calibrate the models and allowed verification of several different mapping techniques. The surface seismic recording effort has been terminated and its emphasis placed on downhole, wall clamped, three-axis geophone recording system. This system should be available for testing during fiscal '78.

INTRODUCTION

During the previous year, Sandia Laboratories has joined with several operating companies to perform diagnostic experiments on gas stimulation via massive hydraulic fracturing. These experiments have covered a wide range of depths, formations, and regional locations to study hydraulic fracturing. The surface electrical potential was the primary means of obtaining this diagnostic information. This system utilizes the fracture well as one of the current electrodes in a typical four element resistivity array. The changing geometry of this current electrode as the conductive fracture fluid is pumped into the ground results in a changing potential pattern at the surface which can then be mapped. The orientation and asymmetry of the fracture can then be determined from the surface. Also the fracture growth periods and lengths of time that the fracture length is being extended can be determined. These potential changes and the theoretical model for them was presented at the SEG meeting in Houston.[1]

Four experiments were conducted during this year and their results indicate that the surface electrical potential system design effort has been completed and its application to hydraulic fracturing has been proven. Yet to be determined are the limitations and capabilities of this system when applied to deeper or smaller hydraulic fracture experiments. These results will have to be determined by both a combination of model tank work and actual field experiments.

*This work supported by the U.S. Energy Research and Development Administration.

The recording of seismic signals associated with hydraulic fracturing on the surface has been discontinued. The results of the January 1976 Wattenberg experiment have been completely analyzed and indicated that fracture signals were not being received at the surface. The seismic effort has been shifted to a downhole, wall clamped seismic system where the planned utilization will be for the breakdown phase. Hopefully seismic signals can be created during the breakdown pumping by varying the rates, pressures and shut in times to determine close in to the wellbore the fracture orientation and height. This should result in some interesting information concerning vertical fracture growth into the overlying and underlying beds of planned containment. This system will be ready for experimental testing during the following year.

BACKGROUND

During September of 1974 Sandia Laboratories joined with El Paso Natural Gas on our first fracture mapping experiment in their Pinedale, Wyoming lease. Sandia using their in-house instrumentation and data collection capabilities applied these to a new measurement area. Both the surface seismic recording system and the first electrical potential system were deployed for this experiment. These initial experiments were followed by a more sophisticated seismic and electrical system the following year. These results have been reported in reference[2]. These initial experiments resulted in Sandia funding from ERDA for the program entitled "Natural Gas Massive Hydraulic Fracture Research and Advanced Technology Project." The total number of experiments conducted to date are tabulated in Table I.

The system that was deployed for the seismic recordings was a wideband continuous analog recording system. The intent was to record at all frequencies where seismic signals could possibly be received in the anticipation that the hypocenter location of these signals could be determined and that they would be fracture related. The wide bandwidth of the system required a tremendous data handling capability and software effort to support the data analysis. These tasks have been completed and have shown conclusively that fracture related signals will not propagate to the surface from hydrofracs at 8000 feet.

The electrical system evolved through several experiments to the present day system. The initial experimens where feasibility was established required considerable time to take one set of data from 24 radial locations. The present system utilizes a computer and multiplex data so that the complete electrical field can be mapped as frequently as every 20 seconds.

ELECTRICAL POTENTIAL SYSTEM

The electrical potential system has evolved over the past three years into the system currently in use. A complete system description including block diagrams and software is given in reference[3]. A brief description of the system will be given here to allow a more comprehensive annual status report. The electrical system is comprised of three subsystems. These are: 1) the current generator, 2) the potential measurement boxes, and 3) the data collection system.

The current generator was designed to provide up to 600 volts and 50 amps of current for use in the surface potential measuring technique. It has the capability to provide bipolar pulses that are controlled in length by either the PDP-11 computer or manually. The current generator is completely isolated so that the energy source only comes into contact with the earth at the two current driving points. Fracture well or downhole current probe in the fracture well is used as one of these points with the other being a remote well located usually more than a mile from the fracture well. The current generator utilizes batteries for the voltage source which are automatically recharged between current pulses.

The potential measurement system is a series of boxes which have inputs from two voltage probes. These voltage probes feed an isolation amplifier which performs the necessary isolation between the power supply lines, data collection lines and the potential probes. The output of the isolation amplifiers modulates a voltage controlled oscillator which in turn is multiplexed to collect 24 sets of data simultaneously.

The data control and collection subsystem utilizes a PDP-11 computer for collecting the data and controlling the current generator. Data is collected by demultiplexing the outpus from the potential measuring boxes digitizing, averaging and storing these on permanent data files for later analysis. Hard copy outputs are available for quick look analysis of test results.

EXPERIMENTAL RESULTS

Tulsa Mini-Frac

During November 1976 a shallow fracture was designed and conducted by AMOCO at a location approximately five miles NE of Tulsa. The purpose of this experiment was to allow verification of both the Sandia surface electrical potential technique as well as the USGS tiltmeter models. The plan called for creating a very shallow vertical fracture that could later be verified by drilling from the surface. The fracture depth was from 40 to 80 feet and a predicted fracture length of 600 feet. A surface potential array was installed and collected data during the 5000 gallon fracture.

Electrical results indicated a fracture orientation of E-W with the main fracture length in the easterly direction. This orientation was later verified when AMOCO drilled into the formation and intercepted the fracture in the easterly direction but did not intercept it to the west. The orientation was also verified by AMOCO's downhole TV camera as well as the USGS tiltmeter data. The significance of this experiment is that it did in fact show that the surface electrical potential technique could not only detect fracture orientation but also provide insight into the asymmetry of the fracture.

Natural Buttes #14

During April 1977 an MHF experiment was conducted as part of a joint industry/ERDA funded program. GPE conducted an MHF experiment on their well NB #14 located south of Vernal, Utah. This was an old well that was being re-fractured. Fracture design called for eight stages of pad and proppant separated by balling off after each stage. In this manner hopefully 15 zones were to be treated. The surface electrical potential data was collected on one minute intervals during the entire fracture operation. Surface potential data showed a significantly different fracture growth than had been expected because of the balling operations. During the first stage apparently three separate fractures were initiated and terminated. One additional fracture was created during the fourth stage. Evidently the remaining time of pumping resulted in these fractures being inflated and receiving the proppant. There was no apparent correlation between fracture growth, fracture termination, and the ball seating on the perforations. Fracture termination is probably associated with formation properties rather than surface conditions. Fracture orientation was also established and fracture growth direction during each of the four stages was seen. By the end of the frac job, the fracture was approximately symmetric and was oriented from NNW to SSE.

This type of data and its interpretations has shed a new light on the usefulness of the surface electrical potential technique. This system can apparently be used not only for determining fracture orientation but will also be useful as an aid in interpreting fracture growth.

Conoco

In March 1977 an experiment was conducted with Conoco in their Big Muddy field, east of Casper, Wyoming. Conoco was planning an enhanced oil recovery project in this field and required knowledge concerning the fracture orientation. Conoco had installed six downhole pressure gages in wells surrounding the fracture well as an independent means of determining fracture orientation. Sandia installed their surface electrical potential data system as a method of independently determining fracture orientation. The fracture was at an intermediate depth and was to be significantly smaller than previous experiments. The well was completed open hole and Conoco furnished a downhole current probe. The downhole current probe probably enhanced the data for this small frac to the point to where it could be interpreted. A Sandia data interpretation was a one-sided asymmetrical fracture that was oriented almost due east. This was later verified by Conoco in their interpretation of their pressure data. Another interesting observation concerning this experiment was that the electrical fracture length was created during the first few minutes of pumping and the balance of the time the fracture length did not significantly grow. This phenomena of quick fracture growth could be explained by leak off of the fracture fluid into the formation during continued pumping. This growth and stop phenomena was also seen on the previous NB #14 experiment.

Natural Buttes #20

In June 1977 a second experiment was conducted with GPE near Vernal, Utah. This experiment was on their well NB #20 at a greater depth than the previous experiment. This fracture design called for eight zones to be treated using the limited entry technique. The surface electrical potential system was installed slightly different for this experiment. The inner radials were located at 1800 feet as before but the outer radial spacing was changed. The model shows that an increased outer radial spacing will enhance the data and because of the deeper fracture it was desired to move the outer radials out as far as possible. This was done by selecting a voltage common well that was located five miles away and using this well as the outer radial for each set of probes. By doing this the outer probe was effectively moved to infinity. The data was collected every minute during the approximately three hours long pumping period. The results indicate that no appreciable fracture length was created at any time during the entire pumping. The potential changes that were seen at the surface were considerably less than those seen on the previous experiment. The only conclusion that we can draw is that the fracture propagated vertically to a much greater extent than had been designed and the horizontal length was much smaller than designed.

SEISMIC SYSTEMS STATUS

Surface Recordings

Seismic data collected with a surface array of seismometers symmetrically located around the AMOCO well during the January 1976 massive hydraulic fracture have been extensively analyzed. The main analysis tool consisted of a computerized procedure for time of arrival locating of seismic hypocenters which was presented in a paper for the October 1976 Computer Use By Engineers Symposium in Albuquerque, New Mexico.[4]

Basically the procedure involves computing and displaying hypocenters via a four dimensional nonlinear optimization utilizing time of arrival information obtained from the cross-correlation of received signals.

Hypocenter location plots were made for the entire ten hour period of the pumping operation. The data were examined in several pass bands and both positive and absolute values of correlation peaks were utilized in order to find shear signals which might be of opposite polarity across the plane of the fracture.

The result of the analysis was that no clustering of hypocenters could be found which might be related to the fracture. Taken over the entire period of the operation the plots were random and symmetrical to the well. The one bright spot in the result occurred after pumping ceased. The plan view plot showed a definite alignment of hypocenters in the N-S direction. Later it was discovered that this location overlaid a pipe line which we now assume was pumping during the fracturing. While this result confirmed the ability of the procedure to plot sources for a linear and relatively continuous process it remained that the fracture was not located.

The conclusion draw is that no signals sufficiently above the background noise to plot the fracture were generated by the January 1976 Wattenberg massive hydraulic fracture operation.

Downhole Seismic System

A wall clamped, three-axis downhole seismic system has been designed and fabricated by Sandia Laboratories for use in the natural gas programs. The purpose of this system is to determine close in to fracture wellbores the orientation and vertical extent of hydraulic fractures. The system is similar to the one developed by Los Alamos Scientific Laboratory for their geothermal project.[5] If seismic signals can be created during the breakdown phase of fracturing operations by controlling pressures, rates and shut ins then these signals can be used to map the fracture plan. The signals must contain both a P-wave and S-wave arrival so that the distance to the seismic event can be determined. The azimuth is then determined by the vector orientation of the arrival of the P-wave. The electronic system has been designed to allow operation on a single conductor logging cable. Power is sent down the cable and the three-axis geophone signals are FM multiplexed and transmitted up the cable. Control circuitry is also provided for clamping and unclamping the mechanism. Preliminary testing has been completed with this unit in a shallow borehole at Albuquerque. Future test plans include fracture experiments at two Sandia sites prior to the use of the system in a commercial well.

CONCLUSIONS

The surface electrical potential system has had the design finalized and is now ready for an applications phase where data from several experiments can be collected and analyzed. To date the system has proven to be much more valuable than its original intent. Not only is fracture orienation being detected but also fracture asymmetry, fracture growth rates and fracture growth periods have also been detected. The system has been operated at a wide range of depths, formation and fracture volume treatments. During the ensuing year plans are being formulated to test this system in several new environments. In conjunction with the electrical system the seismic system will be deployed during the following year. Hopefully the information obtained from the seismic system will help verify the results obtained from the electrical system and add new insight into the fracturing height parameters.

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Table I. Fracture Experiments

Operating Company	Date	Systems Deployed	Location
EPNG	9-74	S&E*	Pinedale, Wyoming
EPNG	7-75	S&E	Pinedale, Wyoming
EPNG	10-75	S&E	Pinedale, Wyoming
AMOCO	11-75	E	Wattenberg, Colorado
AMOCO	12-75	E	Wattenberg, Colorado
AMOCO	1-76	S&E	Wattenberg, Colorado
Columbia Gas	8-76	E	Lincoln County, W. VA.
AMOCO	11-76	E	Tulsa, Oklahoma
GPE	3-77	E	Vernal, Utah
CONOCO	3-77	E	Casper, Wyoming
GPE	4-77	E	Vernal, Utah

*S - Surface Seismic System
E - Electrical Potential System

DETERMINATION OF SPATIAL GEOMETRY OF HYDRAULIC FRACTURES USING SURFACE TILT MEASUREMENTS: A PROGRESS REPORT

by

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ABSTRACT

Hydraulic fracture experiments have been monitored with a surface tiltmeter array to determine the spatial geometry of a fracture. These experiments range over orders of magnitude in depth, design length, pumping time, and volumes of injected material. The gross character of signals recorded within the tilt array is adequately explained by a simple model of an infinitely long inflated fracture in an isotropic half space. Though the theoretical amplitude of the tilt signal is inversely related to the square of the depth, tilt signals have been better defined for the deepest experiments in sandstone than for shallower ones in shale. Definition therefore appears to be less related to depth or size of treatment than to rock type and local structure. When a comparison with other geophysical measurements such as resistivity could be made, the recorded signals were similar in quality for those occasions when well-defined tilt signals were received or when extremely unusual records were obtained. Because the noise sources for deformation and resistivity measurements have little in common, it is assumed that failure to record a signal at all sites is related to failure to generate the designed fracture. Follow up data from the well have supported this assumption. More recent detailed analysis of tilt derivatives and crosscorrelation of tilt with other data such as pressure and flow-rate records of the hydrofracture treatment are improving our understanding of the growth rate of the fracture and temporal variation of width. Improvements in instrumentation and simplification of data analysis may ultimately prove useful for fracture mapping research.

Note: Copies of this report are available from the author.

OVERVIEW OF PROGRESS OF THE EASTERN GAS SHALES PROJECT

by

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ABSTRACT

The Eastern Gas Shales Project was formally initiated in 1976 by the Energy Research and Development Administration (ERDA) as its Morgantown Energy Research Center. The ultimate objective of the Project is to increase the production of natural gas from the Eastern Shale Basins through advanced exploration and extraction techniques. The EGSP expects to achieve many goals and the more significant ones are: To add 3.5 to 7.0 trillion cubic feet of gas to reserves in the Appalachian Basin; to increase average total gas reserves added per well drilled from 300 to 600 million cubic feet; and to increase open-flow production rate of new shale wells from 100,000 to 300,000 cubic feet or more of gas per day. The present status and a summary of important results are presented.

Note: Copies of this report are available from the author.

U.S. GEOLOGICAL SURVEY'S EASTERN DEVONIAN SHALE PROGRAM

by

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ABSTRACT

As a part of ERDA-MERC's Eastern Gas Shales Project, the U.S.G.S. is making an eight-element Shale Characterization and Resource Appraisal of the Devonian black shales of the Appalachian basin. It includes regional stratigraphy, structural analysis, geochemistry of source and reservoir rocks, clay mineralogy, conodont paleontology and thermal maturation indicies, borehold gravimetry, trace element analyses, and a hydrocarbon resource appraisal. Also, the U.S.G.S. has established a data system to store and manipulate information generated by cooperators in the EGS Project.

Prepared for ERDA under Contract No. EX-76-C-01-2287

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INTERNAL SURFACE AREA AND POROSITY IN EASTERN GAS SHALES FROM THE SORPTION OF NITROGEN, CARBON DIOXIDE, AND METHANE - A STATUS REPORT

by

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ABSTRACT

The adsorption of N_2 at -196°C and of CO_2 at -77°C on Eastern gas shales reveals significant differences in their micropore structures. Owing to differences in the activated diffusion of the two gases at their respective adsorption temperatures, as studies on molecular sieves and coals have shown, CO_2 is able to penetrate pores less than 4-5 Å in diameter, whereas N_2 is unable to do so. One measure of this difference is in the internal surface area (ISA) estimated from the BET method. For example, shale samples from a Kentucky core, with CO_2 as the adsorbate, have ISA values ranging from 10 to 39 m^2/g, whereas the ISA values from N_2 adsorption on the same samples range from 0.8 to 8.7 m^2/g. The diffusion rate of a gas initially contained within such an ultramicroporous network will be greatly decreased in comparison with the diffusion rate from shales containing larger pores.

High-pressure (up to 80 atmospheres) methane adsorption isotherms near room temperature are shown for selected shale samples. These isotherms provide supplemental information with regard to total porosity and the gas-holding capactiy of shales at depth of burial.

INTRODUCTION

The Illinois State Geological Survey, in conjunction with the Energy Research and Development Administration, is extensively involved in both geologic and geochemical studies of the Eastern gas-bearing Devonian shales.

In the geologic studies, the lithology, stratigraphy, and structure of the New Albany Shale Group in Illinois are being analyzed to determine those characteristics of lithology, thickness, regional distribution, vertical and lateral variability, and deformations most relevant to the occurrence of hydrocarbons. Mineralogic and petrographic properties are being characterized in detail. Additionally, index properties, directional properties, and strength parameters on oriented core samples are being studied.

Geochemically, not less than 49 major, minor, and trace elements are to be determined on 900 shale samples. The data generated will be used to

Prepared for the Energy Research and Development Administration, under Contract No. E-(40-1)-5203.

evaluate (1) the potential economic importance of trace element concentrations in organic-rich shales, (2) new geochemical exploration techniques for natural gas, (3) trace element enrichment in shale organic matter, (4) the occurrence of heavy metal sulfides in shale, (5) potential catalytic effects of trace elements on shale pyrolysis yields, and (6) potential disposal problems.

Chemical and physical methods are to be developed for separating organic and inorganic phases of shales, and the trace elements associated with the various phases are to be determined. The relative distribution of hydrocarbons in selected samples will be determined.

In order to reveal the nature of the pore structure in these shales, sorption studies at low temperatures are to be made with nitrogen and carbon dioxide as adsorbates. Methane adsorption isotherms also are to be studied at elevated pressures (up to 80 atmospheres). The present paper is a status report of the sorption studies.

One of the most difficult problems faced in the physical characterization of materials is determining the nature and extent of porosity. Polycrystalline aggregates--which are the rule rather than the exception in nature--have much more porosity than is generally recognized. Pore structure can be of several types. For example, a substance such as limestone contains random-sized closed pores. Montmorillonite contains pores of a special shape--those that exist between the laminae of platelet crystal packets. Some substances, such as zeolites, coals, and the black gas-bearing shales under discussion in this report, contain a partially interconnecting open-pore structure, with the smallest pore channels having diameters of molecular dimensions (less than 10 Å). These ultramicropores are of special significance in that they are large enough to contain appreciable quantities of certain gases of small molecular dimensions, such as methane and other hydrocarbons having little side branching, yet they are so small that they markedly influence the diffusion rates of the contained gases.

The only experimental approach that provides useful information with regard to the porosity associated with these ultramicropores is the use of gas adsorption (sorption) methods. Low-angle X-ray scattering and helium displacement measure the total porosity only. Mercury intrusion is limited to pores having diameters of about 30 Å and larger.

Studies by Breck et al.[1] and Lamond[2] on molecular sieves, and by Walker and Geller[3] and Anderson et al.[4,5] on coals have established that carbon dioxide as an adsorbate at -77°C is able to penetrate pores having diameters less than about 4-5 Å, whereas nitrogen, the adsorbate normally used at -196°C in the classic BET method[6], fails to do so. Thus, CO_2 at -77°C becomes a valuable molecular probe, supplementing N_2 adsorption data, for estimating that amount of internal surface area or porosity associated with pores less than 4-5 Å in diameter.

The use of CO_2 as an adsorbate for this purpose has been reviewed recently by Thomas and Damberger[7]. Even though the various theories upon which gas adsorption methods are based are inadequate when applied to pores of molecular dimensions, the relative adsorption values obtained are reproducible and useful for correlative purposes.

The use of methane as an adsorbate near room temperature and at increased pressures yields isotherms from which the gas-holding capacity of a given shale sample can be estimated at its initial depth of burial.

EXPERIMENTAL PROCEDURES

Data for internal surface area (ISA) measurements with N_2 and CO_2 as adsorbates at -196°C and -77°C, respectively, were obtained by a dynamic-sortion method. This method is commonly called the gas chromatographic method, as the principles involved in the measurements are similar to those used in gas chromatography. Apparatus is basically that first described by Nelsen and Eggertsen[8] and later refined by Daeschner and Stross[9].

For the high-pressure (1 to 80 atmospheres) methane adsorption isotherms, apparatus similar to that described by Dubinin et al.[10] was constructed with slight modifications for improved readout of pressure.

Shale samples were crushed and screened. The 40- x 120-mesh (about 425 to 125 μm) sieve fractions were used for the internal surface area measurements with N_2 and CO_2 as adsorbates. The 6- x 12-mesh (about 3.4 to 1.7 mm) sieve fractions were used for the high-pressure methane adsorption isotherms.

For the ISA determinations, shale samples of 0.5 to 1.0 g are outgassed at 110°C in a stream of helium for 3 hr. Three-point BET plots are used with N_2 as the adsorbate at -196°C. An equilibrium time of 10 min was suitable for each point. For CO_2 as the adsorbate, however, an equilibrium time of 16 hr is necessary, owing to the slow activated diffusion. A single-point BET plot passing through the origin is used as a measure of the ISA.

For the high-pressure methane adsorption isotherms, approximately 5.5 g of sample are weighed into a high-pressure cell, and outgassing is conducted under vacuum until a pressure of less than 10^{-3}mm is attained. The dead space is determined with helium. Known increments of methane are transferred to the cell, and pressure differences are determined at constant temperature as a measure of the uptake of methane by the sample.

At the present time samples from only two cores have been studied. The more recent core is designated Orbit Gas #1 Clark Well from Christian County, Kentucky (near Crofton). The older core (1939) is designated Miller #1 Sample from Sangamon County, Illinois (near Mechanicsburg).

RESULTS AND DISCUSSION

A surface area value for a shale sample, either from CO_2 or N_2 adsorption data, will depend to some extent upon the composition of the sample (clay minerals ratio; presence of silica, carbonates, etc.) and the crystallite sizes of the components. Accordingly, too much significance should not be attached at this time to the ISA values shown within either the third or fourth columns of Tables 1 and 2. The most revealing values are the ISA ratios shown in the last column of each table.

When this ratio is large, the sample contains a large proportion of pores less than 4-5 Å in diameter. CO_2 penetrates these pores at -77°C whereas N_2

at -196°C does not. When the ratio is large, the sample has a more compact structure with regard to porosity. Such a sample, if it contains gas, will release that gas with great difficulty. That is, the diffusion rate will be low.

On the other hand, if the ratio is small, it is readily ascertained from the data that N_2 at the temperature of liquid nitrogen (-196°C) reaches most of the ISA that is reached by CO_2 at -77°C. Very little porosity is associated with pores less than 4-5 Å in diameter. Thus, with a mean pore diameter somewhat larger in such samples, the diffusion rate of methane will be increased.

For the most part, the ISA ratios for the shale samples from the Kentucky core (Table 1) are appreciably larger than those from the Illinois core (Table 2). Samples from the Kentucky core are darker than those from Illinois, indicating that there is more organic matter in the former core. The increased organic matter no doubt contributes to the high CO_2 ISA values relative to the N_2 ISA values in the Kentucky samples as the organic matter helps to fill the pore space, thereby decreasing the diameters of pore entrances and channels. The darker samples (16L1 and 17L1) from the Illinois core also give the greatest ISA ratios among the samples from this particular core.

Evidence of this partial pore filling by organic material is provided by outgassing experiments at elevated temperatures. Two additional samples of 01C1 from the Kentucky core, for example, were outgassed under helium at 230°C and 340°C, respectively. The data are summarized in Table 3.

It is seen that although the surface area from CO_2 adsorption does not change markedly, the surface area from N_2 adsorption increases about fourfold after an outgassing temperature of 340°C. The weight loss also increases sharply. This indicates that organic material which is held tenaciously in the pores at 110°C, and even at 230°C, migrates from the pores at the highest temperature, making more of the internal surface available for N_2 adsorption.

As was mentioned earlier, the ISA measurements with CO_2 and N_2 as adsorbates are relative measurements which provide some idea of the "tightness" of the shale structure that governs the rate of release of the gas contained within the smallest pores. These measurements do not provide information, however, on the possible gas holding capactiy of a given shale at its depth of burial. The gas-holding capacity of the shale will be governed by relatively large pores, if present in the shale, which do not contribute significantly to the ISA values. The high-pressure methane adsorption isotherms provide valuable supplemental information.

Three samples were selected from the Kentucky core for evaluation. These samples, based on high, low, and intermediate ISA ratios, were 01C1, 06C1, and 03C1. Plots of the high-pressure methane adsorption data for the three samples are shown in Fig. 1.

The sample (06C1) giving the lowest (1.67) ISA ratio is capable of holding much more methane at depth than is the sample (01C1) giving the greatest (26.2) ISA ratio. The mean pore size in the former sample is larger. This is clear from a comparison of the nitrogen ISA values (8.7 m^2/g for sample 06C1, and 1.5 m^2/g for sample 01C1). The gas-holding capacity of sample 03C1 is the poorest of the three samples. It also has the lowest (1.26 m^2/g) nitrogen ISA value.

One cubic centimeter of gas adsorbed (at STP) per gram of shale is equivalent to 32.1 ft^3 of gas per ton of shale. If one uses the "rule of thumb" that every foot of depth of burial in sediments increases the pressure 1 psi[11], then the pressure at 2200 ft is ∿2200 psi (∿150 atmospheres). Extrapolation of the data in Fig. 1 to 150 atmospheres indicates that the gas-holding capacity of sample 06C1 is approximately 6 cm^3/g, or close to 200 ft^3/ton shale, whereas the gas-holding capacity of sample 01C1 is about one-third as great.

Sufficient data have not yet been generated to permit additional interpretation.

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TABLE 1 - INTERNAL SURFACE AREA VALUES FOR SHALE SAMPLES FROM CHRISTIAN COUNTY, KENTUCKY (CORE 01KY)

Sample No.	Feet Depth to Top of Sample	ISA, m^2/g CO_2	ISA, m^2/g N_2	ISA, CO_2/N_2
01C1	2182.25	39.3	1.50	26.2
02C1	2191.15	27.0	1.33	20.4
03C1	2220.30	20.4	1.26	16.2
04C1	2230.20	13.8	5.00	2.8
05C1	2240.10	13.8	1.04	13.2
06C1	2250.00	14.5	8.71	1.67
07C1	2260.30	31.3	1.52	20.6
08C1	2270.30	11.8	1.43	8.5
09C1	2280.00	11.1	1.05	10.6
10C1	2290.75	14.7	1.08	13.6
11C1	2299.75	12.7	0.92	13.8
12C1	2310.50	10.0	1.04	9.6
13C1	2318.80	14.3	0.82	17.4

TABLE 2 - INTERNAL SURFACE AREA VALUES FOR SHALE SAMPLES FROM SANGAMON COUNTY, ILLINOIS (CORE 01IL)

Sample No.	Feet Depth to Top of Sample	ISA, m^2/g CO_2	ISA, m^2/g N_2	ISA, CO_2/N_2
01L2	1576	27.3	27.4	$\sim$1.0
03L1	1589.4	12.7	12.1	$\sim$1.0
04L1	1602.0	11.8	11.8	$\sim$1.0
05L1	1615.1	16.6	17.8	0.93
07L1	1631.6	10.1	8.4	1.2
09L1	1647.4	22.8	23.5	$\sim$1.0
09L2	1656.2	23.3	23.4	$\sim$1.0
10L1	1657.6	16.4	12.6	1.3
11L1	1667.5	30.2	20.3	1.5
12L1	1678.6	30.8	25.7	1.2
13L1	1688.0	31.2	25.7	1.2
14L1	1698.2	31.5	19.0	1.7
15L1	1710.0	34.4	11.8	2.9
16L1	1723.4	34.0	8.3	4.1
17L1	1730.6	25.9	5.5	4.7
18L1	1740.2	20.5	6.0	3.4
19L1	1753.5	25.1	6.2	4.1
20L1	1763.3	19.3	11.5	1.7
21L1	1776.2	22.6	11.5	$\sim$2.0

TABLE 3 - INTERNAL SURFACE AREA VALUES AFTER DIFFERENT OUTGASSING TEMPERATURES

Sample 01C1

Outgassed 3 hours (°C)	ISA, m^2/g CO_2	ISA, m^2/g N_2	ISA, CO_2/N_2	Weight Loss, %
110	39.3	1.50	26.2	$\sim$1.0
230	44.3	1.57	28.2	$\sim$2.0
340	35.8	6.46	5.5	$\sim$6.0

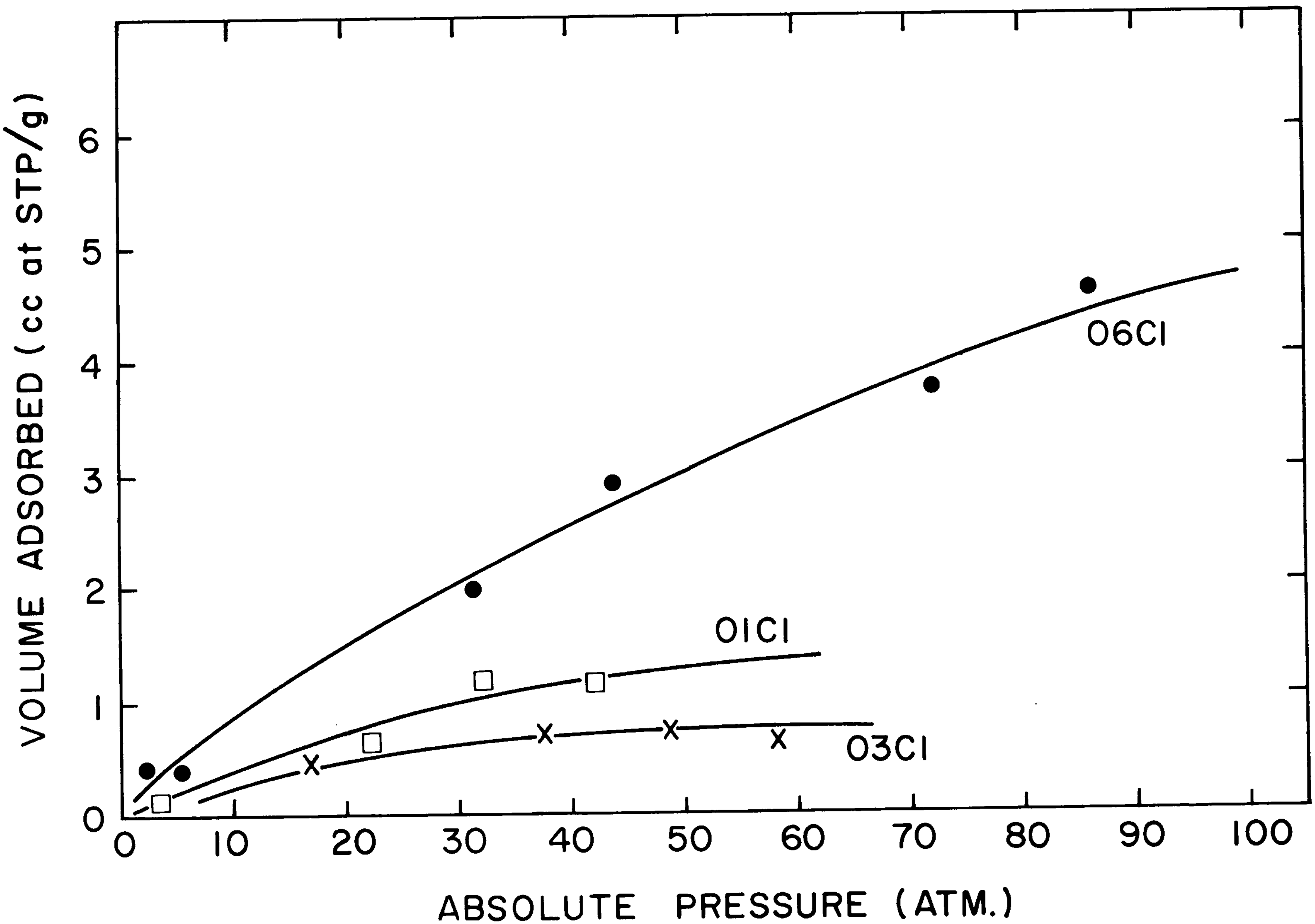

FIG. 1-METHANE ADSORPTION ISOTHERMS AT 28°C

CHARACTERIZATION AND ANALYSIS OF DEVONIAN SHALES AS RELATED TO RELEASE OF GASEOUS HYDROCARBONS

by

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ABSTRACT

As part of the Resource Inventory and Shale Characterization subprojects of ERDA's Eastern Gas Shales Project, Battelle's Columbus Laboratories is conducting a program to determine the relationships between shale characteristics, hydrocarbon gas content, and well location. Ultimately about 1000 core samples of gas bearing Devonian shales will be selected and sealed in special containers to preserve their approximate "down-hole" condition, and the gas-release characteristics and various chemical, physical, and lithologic characteristics will be determined.

Partial data have now been collected on about 150 samples from 8 different wells in both the Appalachian and Illinois basins. Initial findings and possible implications of them are discussed.

INTRODUCTION

This program was initiated in July 1976 as a part of ERDA's Eastern Gas Shales Project (EGSP). The objective of the program is to determine the relationships between shale characteristics, hydrocarbon gas content, and well location to provide a sound basis for defining the productive capacity of the Eastern Devonian shale deposits and for guiding research, development, and demonstration projects to enhance the recovery of natural gas from the shale deposits. The program includes a number of elemental tasks as a part of the Resource Inventory and Shale Characterization subprojects and is designed to provide large quantities of support data for the EGSP.

Prepared for ERDA under Contract No. E(40-1)-5205

Approximately 1000 core samples of gas bearing Eastern Devonian shale will be examined in the program. After the characterization data for individual wells have been compiled, a regression-type analysis for pattern recognition will be performed to establish the interrelationship between the shale characteristics, the hydrocarbon gas content, and well locations from which the samples were obtained.

The work involves six tasks: core sampling, gas content and gas release kinetics, chemical characterization of the shale, physical characterization of shale, lithology of shale, and data interpretation and correlation.

The project was initiated in July 1976 and active laboratory work was started in September 1976. Approximately 350 core samples have now been selected and encapsulated from 9 wells, 5 in the Appalachian Basin and 4 in the Illinois Basin. The well locations are given in Table 1. Partial data are now available on 150 samples from 8 of the wells and some patterns and relationships are becoming apparent. In this progress report, emphasis will be on the relationships among the initial gas release data, well location, and some of the observed characteristics of the shale.

Core Sampling and Encapsulation

Core sampling for the EGSP is done by a team, under the supervision of the West Virginia Geological Survey, including in addition to the supervising geologist, representatives from the appropriate State Geological Survey, from the producing company, and from Battelle's Columbus Laboratories. After the core has been retrieved, reassembled, oriented, marked, and described, samples are taken by the Battelle representative for use in experiments and characterizations being conducted at Battelle, Mound Laboratories, and Juniata College. The standard sampling sequence involves the collection of core samples at 10-foot intervals for Battelle, at 30-foot intervals for Mound Laboratories, and at 50-foot intervals for Juniata College.

The selected samples are placed in fruit juice cans and lids are applied and sealed with a canning machine for subsequent transport to the various laboratories.

Analytical Procedures for Initial Gas Release

The canned core samples are logged in and normally are stored for a minimum period of 3 weeks after canning to allow them to come to equilibrium. Some of the sealed cans bulge and distort during this equilibrium period. Many of the core sections from the recent well in Wise County, Virginia exhibited considerable outgassing during the initial examination prior to canning and many of the cans bulged noticeably within a few hours after sealing. Because of the rapid and excessive bulging, the cans were checked for possible leaks approximately two weeks after canning. Leaks were detected in 16 out of 72 samples checked. Gas analyses were made on these and other bulged, but not leaking, cans as quickly thereafter as possible. Subsequent checks on sealed cans from earlier wells that had not yet been analyzed revealed that some of them also were leaking and, as will be discussed later, the gas composition data suggest that some of the other cans probably had leaked before the analyses were made. Sturdier sample cans are being secured for future wells and procedures are being planned for monitoring the release of gas from the time the sample is canned.

The canned samples after the standard equilibrium period are tapped using the can sampling device shown in an exploded-view in Figure 1. The can sampler is evacuated after it is clamped to the can and the metal punch is then driven through the can top, thereby connecting the gauge and sampling volume to the free space surrounding the shale samples within the can. Two gauges are used for pressures within the cans; an Ultec gauge for pressures less than 1500 torr and an Ashcroft gauge for pressures up to 60 psig. The observed can pressure is reported in torr (mm Hg). A valving system allows a gas sample to be withdrawn from the sampler and entered into a 1 cc constant temperature sample loop. A solenoid valve controls the injection of samples into the chromatograph.

An Aerograph 1520B gas chromatograph is used for species identification. Thermal conductivity detection is employed. The carrier gas is helium at 50 psig. An Altech CTR column separates the gaseous species; the CTR is essentially a column within a column--a molecular sieve surrounds a Porapak mix. With this column it is possible to separate O_2, N_2, CO_2, and light hydrocarbons (through C_6). The detector signal is fed to a Hewlett Packard 3380A integrator and species are identified by their retention times. A standard gas mixture was prepared and includes all major species found in shale cans to date. The standard consists of (v/o):

N_2	51.11	CH_4	29.51
O_2	3.76	C_2H_6	8.50
CO_2	5.61	C_3H_8	1.52

The standard is run daily; shale gas concentrations are determined by the external standard method. Butanes and pentanes, when present, are calculated from their specific response factors. These have been previously determined for this particular experimental set up. All values are reported in volume percent.

In addition to the routine off-gas analysis performed for each as-received shale can, random samples are selected for additional gas analysis. An Aerograph 2800 gas chromatograph is used. Flame ionization detection is employed and species are separated with capillary columns. The 2800 has been calibrated for identification of over 100 hydrocarbons and detects species in ppb concentrations. To date, traces of: propylene, 2-methyl-pentane, 2-methyl 2-butene have been identified; however, the major species remain as reported: CO_2, O_2, N_2, methane, ethane, propane, butanes and pentanes.

After the initial gas analyses are completed, the can is opened, the shale sample is removed, weighed, photographed and described, and samples are taken for the various characterizations and analyses that are to be made. The bulk volume of the shale is subsequently calculated from the measured bulk density and the free gas space in the can is calculated by difference from the known volume of the can. The data from the gas analyses, from the various characterizations and chemical and lithological analyses of the shale samples, and digitized data from well logs are keypunched onto computer cards for subsequent calculations, statistical analyses, and comparisons. Table 2 is an example of a computer print-out of the initial gas release data from one of the wells. Figures 2 and 3 are examples of computer-generated plots of gas analysis data versus depth of the sample for that well and for another well.

Gas Content of Shale and Initial Release of Gas

As is evident from the data in Table 2 and the plot of part of that data in Figure 2, the gas content and the composition of the gas released from canned shale samples from Well P-1 varies substantially and apparently randomly with depth. A comparison of Figures 2 and 3 reveals that there are substantial differences between wells in the gas content per unit volume of shale. For Well C-2 (Figure 3), the unit gas content ranges mostly between about 0.1 and 0.5 cu ft per cu ft of shale, with a general trend of increasing gas content with increasing depth. For Well P-1 (Figure 2), on the other hand, the unit gas content is much greater and generally falls between 1 and 3 cu ft per cu ft of shale and there does not appear to be any general trend with respect to depth.

The composition of the gas also varies substantially with depth and between wells. Figure 4 is a plot of the methane content (as percentage of the total hydrocarbon gas released) versus depth for Well P-1 and Figure 5 is a similar plot for Well C-2. Again, for Well C-2 a general trend with depth is evident whereas for Well P-1, there is no clear trend. For C-2, the relative methane percentage generally decreases with depth and ranges between about 60 and 80 percent. For P-1, the methane content (with the exception of the shallowest sample), ranges between about 85 and 95 percent irrespective of the depth.

These two wells were selected as examples illustrative of the kinds of differences observed initially between the Appalachian and Illinois Basin wells. Plots of relative methane content versus the total hydrocarbon content of the released gas for these two wells are remarkably different (Figures 6 and 7). For the Appalachian Well (C-2, Figure 7), the methane content clearly is an inverse function of total hydrocarbon gas. For the Illinois Well (P-1, Figure 6), the methane content is either independent of total hydrocarbon or is a direct function of it. Gas release data from three additional Appalachian Wells and two additional Illinois Basin Wells showed the same direct relationship between methane and total hydrocarbon for Illinois Basin Wells and the same inverse relationship for Appalachian Wells (except for a few isolated samples). However, the gas release data from the most recent Appalachian Basin Well (C-338) fit the Illinois Basis pattern both in gas composition (i.e., high methane content) and amount of gas released, between 1 and 3 cu ft per cu ft of shale. The clear distinctions seen between Appalachian Basin Wells and Illinois Basin Wells are blurred somewhat by these new data and plots of methane content versus total hydrocarbon that incorporate all of the available data do not show an obvious relationship for Appalachian Basin Wells (Figure 8) although the direct relationship still appears to hold for Illinois Basin Wells (Figure 9).

The most important conclusion to be drawn from the gas release data so far is that each well is unique and that generalizations about relationships observed for one well or for wells within a given area may not be valid for other wells or other areas. A corollary is that a valid assessment of the gas resources of the Devonian shales requires data from many wells throughout the entire deposits.

A further complicating factor in attempting to assess the gas resources of the Devonian shales from gas analysis data on canned samples is the fact that some of the cans have leaked unknown amounts of hydrocarbon gas. As indicated earlier, leaking was detected in a substantial number of canned samples from one of the wells within two weeks after canning and checks on other cans have shown some of them to be leaking months after canning. An examination of the gas analysis data on other samples suggests that many of the cans may have leaked between the time they were sealed and the time that they were tapped for analysis. For example, the gas analysis results for one sample showed the total hydrocarbon content in the free space to be 90.4 percent and the nitrogen content to be 8.56 percent. If we assume that the free space contained only air at the time of canning (i.e., the gas composition was essentially 80 percent nitrogen and 20 percent oxygen) and the pressure at the time of sealing was close to one atmosphere (760 torr), the pressure at the time of tapping should have been about 7100 torr. The measured pressure was 740 torr, about an order of magnitude low, suggesting that appreciable leakage had occurred or that the sample was outgassing sufficiently during the time it was being canned to displace most of the air in the free space before it was sealed. In either case, a calculation of the gas content per unit volume of shale based on the observed pressure and gas composition at the time of tapping, underestimates the gas content in the shale in-situ by an unknown amount, perhaps as much as a factor of 10. Thus, extrapolation of current gas analysis data to produce estimates of the gas recoverable from the Devonian shales result in very shaky numbers at best. Steps that are being taken to eliminate leakage and to monitor gas composition and gas release from the time of canning will decrease the uncertainty in the future and will provide more reliable information on the areal and depth variations in the gas content of the shale.

Shale Characteristics

After the initial gas content has been determined, the shale samples are examined and characterized in a variety of ways. Sufficient data have been accumulated now from some of these examinations and characterizations on five of the wells for some patterns and relationships among initial gas content and shale characteristics to be discernible. So far there appears to be a general inverse relationship between initial gas content and the bulk density of the shale. A less firm, but still general, direct relationship between initial gas content and total carbon content is observed.

Surprisingly, there seems to be no simple relationship between bulk density and porosity. Although one would expect that low bulk density would be accompanied by high porosity (thus, accounting for higher initial gas content), this is not always the case. Likewise, one would expect high open porosity to be accompanied by high surface area, whereas the reverse seems to be more common. Thus, in spite of the good correlation between bulk density and initial gas content, there appears to be no correlation between initial gas content and porosity or surface area.

It should be pointed out that the observed relationships (or lack of them) between gas content and shale characteristics are based on a relatively small number of samples from the first five wells sampled and may be peculiar to these wells. As additional data are gathered some of the puzzling aspects may be clarified.

Future Work

The coring and sampling of additional wells throughout the Eastern Devonian shales is continuing and data are now being gathered at a rate of about 25 samples per month. As more experience is gained and additional data are accumulated, the level of uncertainty will decrease and more reliable and, hopefully, more meaningful conclusions about the gas content and the relationships among gas release characteristics, shale characteristics, and well location will emerge.

TABLE 1. IDENTIFICATION OF CORED WELLS AND SAMPLES SELECTED

Well Code Number	Location of Well	Well Operator	Date Sampled	Core Depth Interval, Feet	Number of Samples
C-1	Lincoln County, WV	Columbia Gas	Jan. 1976	2746 - 4045	82
C-2	Lincoln County, WV	Columbia Gas	Jan. 1976	2655 - 3971	17
R-109	Washington County, OH	River Gas	Jul. 30, 1976	3494 - 3705	25
P-1	Sullivan County, IN	Energy Resources of Indiana, Inc.	Sept. 1, 1976	2495 - 2595	11[(a)]
O-1	Christian County, KY	Orbit Gas	Sept. 18, 1976	2183 - 2319	13[(b)]
C-336	Martin County, KY	Columbia Gas	Nov. 6, 1976	2434 - 3405	117[(c)]
T-1	Effingham County, IL	Tri-Star	Feb. 13-18, 1977	3006 - 3106	15[(d)]

(a) An additional 6 samples were selected and encapsulated for other ERDA contractors.

(b) An additional 4 samples were selected and encapsulated for other ERDA contractors.

(c) An additional 90 samples were selected and encapsulated for other ERDA contractors.

(d) An additional 16 samples were selected and encapsulated for other ERDA contractors.

TABLE 2.

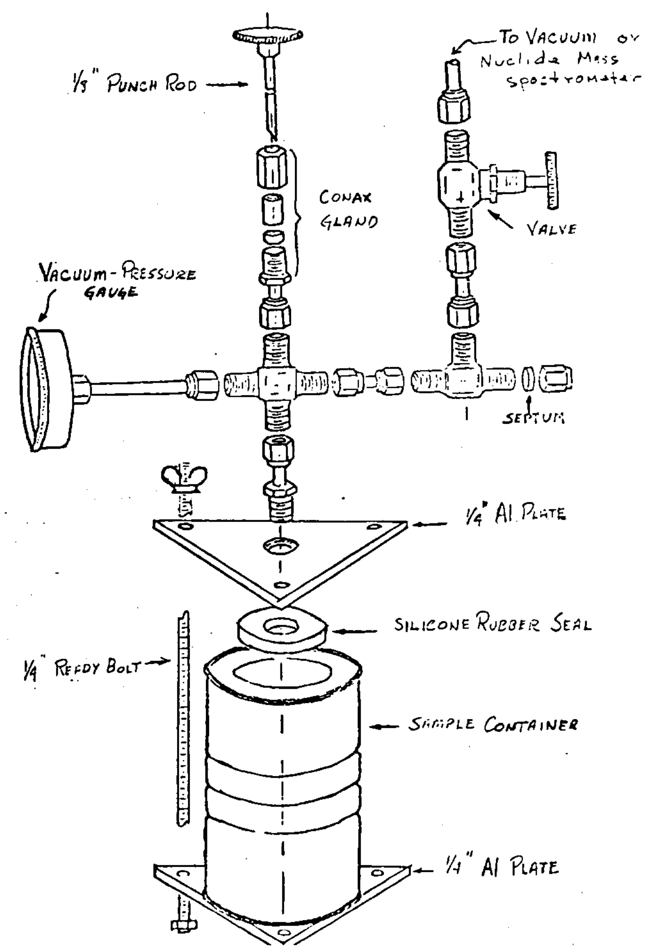
INITIAL GAS RELEASE DATA: WELL P- 1

SAMPLE I.D	PRESSURE T - P	FREE VOLUME CC	CORE VOLUME CC	OPEN POROSITY PCT.	METHANE	ETHANE
P 1-2495.	900.	987.	563.	5.08	21.47	4.61
P 1-2505.	1345.	301.	649.	.64	56.41	3.60
P 1-25[illegible].	1900.	950.	500.	1.06	58.46	4.19
P 1-25[illegible].	2104.	797.	653.	.55	60.63	2.59
P 1-25[illegible].	1770.	720.	733.	1.67	54.60	2.27
P 1-25[illegible].	1700.	735.	715.	2.26	61.32	6.01
P 1-2554.	1900.	647.	603.	1.61	62.95	5.42
P 1-25[illegible].	1390.	703.	742.	1.93	52.58	5.04
P 1-25[illegible].	1970.	780.	670.	.62	62.81	4.60
P 1-25[illegible].	1340.	741.	709.	.62	45.00	3.30
P 1-25[illegible].	2030.	573.	877.	.77	59.01	4.95

SAMPLE I.D	PROPANE	BUTANE	PENTANE	TOTAL HYDROC.	NITROGEN	OXYGEN	CARBON DIOXIDE	GAS RELEASED PER UNIT VOLUME OF SHALE
P 1-2495.	3.53	1.72	.63	31.96	65.87	.91	1.27	.60
P 1-2505.	.22	0.00	0.00	70.23	21.06	2.18	6.53	1.53
P 1-25[illegible].	.26	.05	0.00	62.96	29.95	2.68	4.41	2.99
P 1-25[illegible].	0.00	0.00	0.00	63.19	28.14	1.88	6.79	2.14
P 1-25[illegible].	1.65	0.00	0.00	58.52	31.29	2.31	7.92	1.35
P 1-25[illegible].	.20	0.00	0.00	67.53	27.72	.54	4.22	1.55
P 1-2554.	.34	.07	.03	68.81	27.23	.65	3.31	1.38
P 1-25[illegible].	1.63	.59	.29	60.13	35.62	.74	3.52	1.05
P 1-25[illegible].	0.00	0.00	0.00	67.41	27.33	.12	5.14	2.04
P 1-25[illegible].	0.00	0.00	0.00	48.30	40.40	4.10	7.20	.89
P 1-25[illegible].	2.36	.98	.30	67.60	25.68	.56	5.51	1.18

B.C.L. CAN SAMPLER

FIGURE 1.



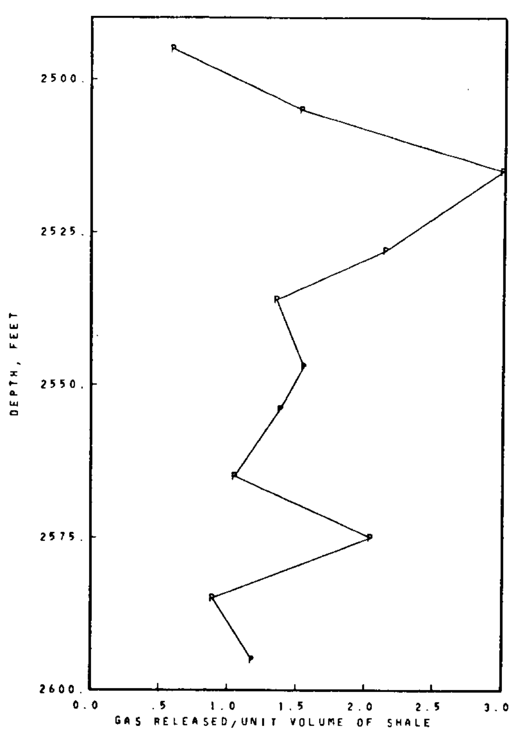


FIGURE 2.

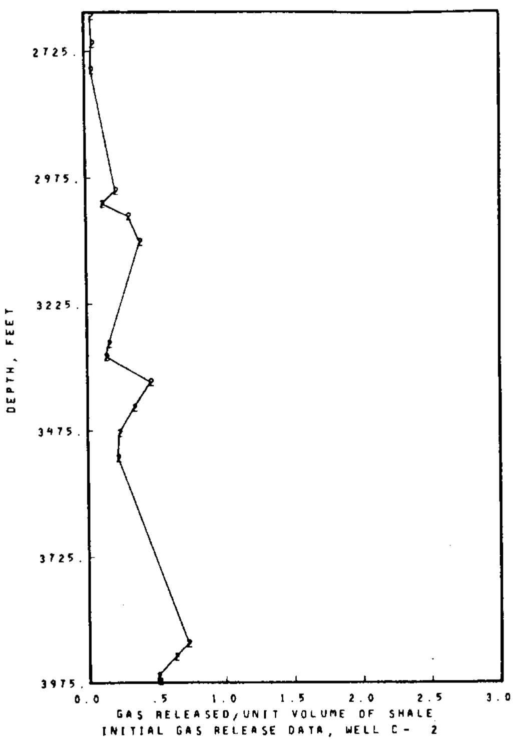
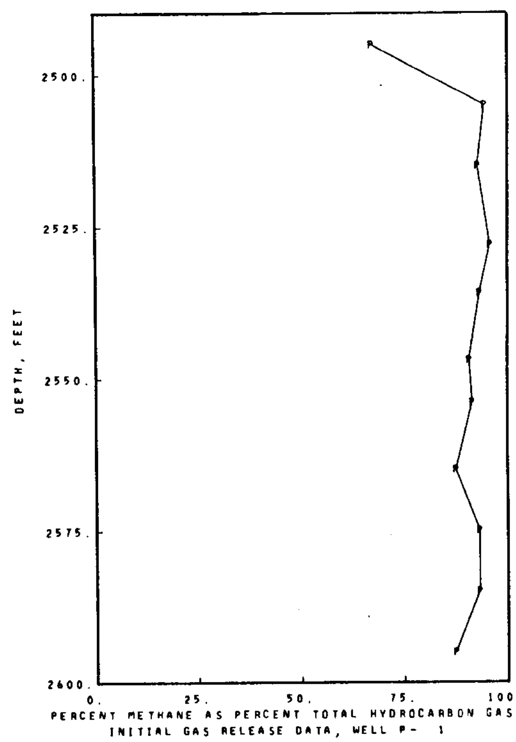


FIGURE 3.



FIGURF 4.

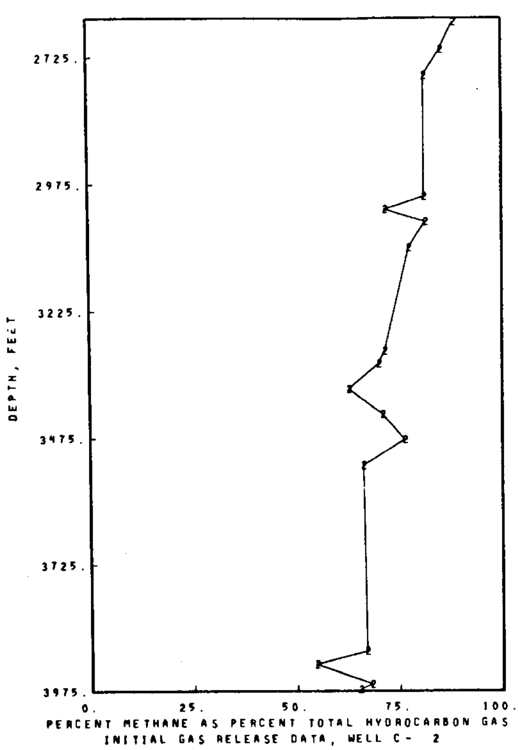


FIGURE 5.

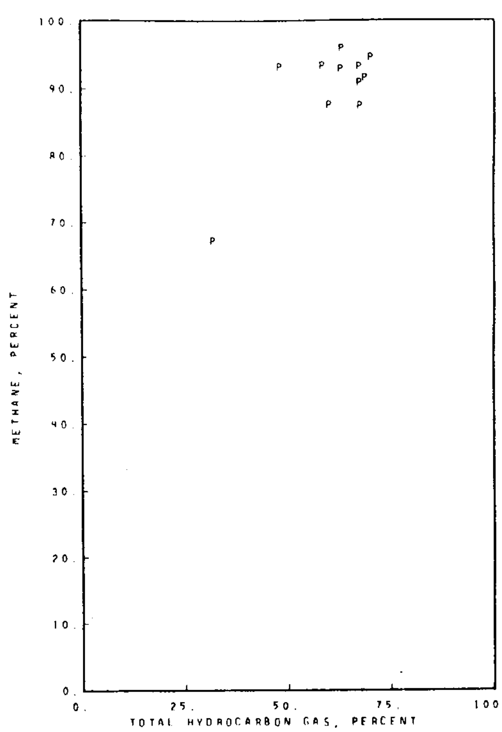


FIGURE 6.

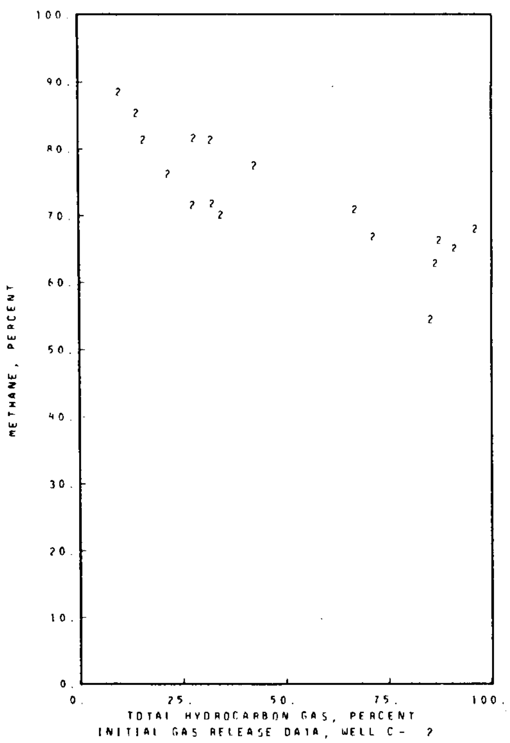


FIGURE 7.

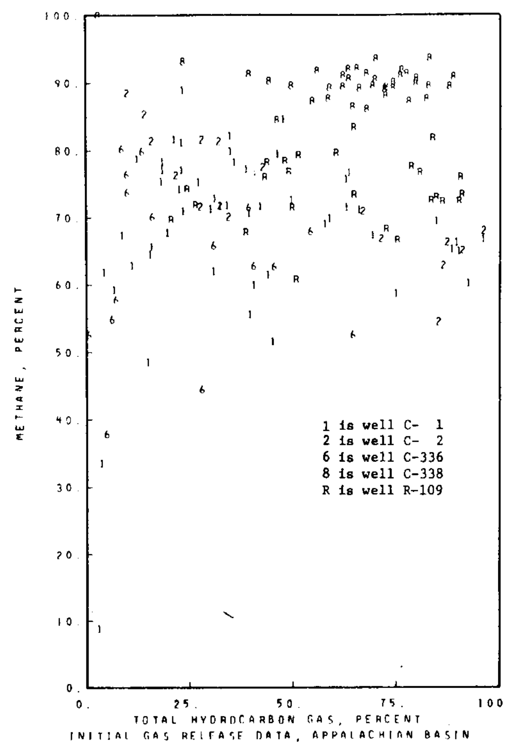


FIGURE 8.

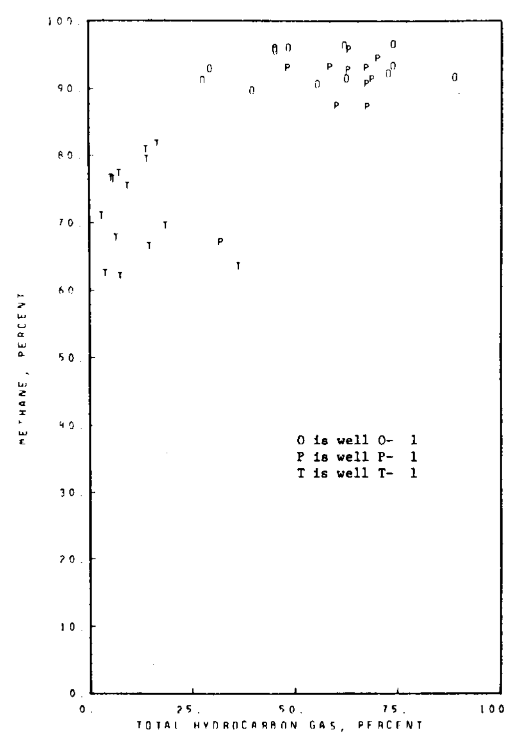


FIGURE 9.

CHARACTERIZATION OF THE DEVONIAN SHALES IN THE APPALACHIAN AND ILLINOIS BASINS

by

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ABSTRACT

The characterization of the nature of the Devonian Shales in the Appalachian Basin is being addressed by several geochemical and geophysical methods.

The outgassing characteristics of the shale are being investigated using gas chromatography and mass spectrometry. An extensive geochemical characterization of the samples is also being performed.

Mechanical testing and mass spectrometry have been integrated to provide some insight into the mechanical properties of the shale and gas released from the shale as a function of newly exposed surface area. Mechanical tests are also being performed in an attempt to determine the effects of moisture on the mechanical properties of the shale.

Dilatometry is being used to study the swelling characteristics of the shale samples as a function of exposure to water and other fracturing fluids.

Several other methods of investigation also are serving to characterize the Devonian Shales and their fuel resources.

*Mound Laboratory is operated for the U. S. Energy Research and Development Administration by Monsanto Research Corporation (Contract No. EY-76-C-04-0053).

INTRODUCTION

The gas resources of the Devonian Shale of the Eastern United States must be considered a viable energy resource. A conservative working estimate indicates that there are approximately 2400 tcf of gas in just the Appalachian Basin. If only ten percent of that gas is recovered, enough gas should be available to satisfy our national needs for approximately ten years.

The Eastern Gas Shale Project has as its long-range objectives an orderly accumulation of a data bank for accurately assessing and characterizing the resource and provision for an economical and efficient production of gas. Mound Laboratory is assisting in the determination of the resource inventory and is cooperating in the studies designed to determine the geological, geophysical, and geochemical properties of the shale.

PROGRAM OVERVIEW

The initial objective of our investigation is to analyze various core samples using standard geochemical techniques and newer methods of analysis. This investigation should aid in arriving at an accurate resource assessment. The results of the investigation should define the relationships between the structure, the chemistry, the fuel content, and the mechanical behavior of the shales from various regions in the Appalachian, Illinois, and Michigan basins. The study will also supply a sufficient amount of data to a statistical base that will serve not only to key resource assessment to secondary indicators but will also provide a valid base for evaluating the efficiency and accuracy of the new methods of analysis.

Other segments of the program will address the permeation of the gas through the reservoir rock, and the effects of fracturing fluids on the mechanical and permeation properties of the shale.

Radionuclides present in the shale will also be assessed.

HYDROCARBON EVALUATION

To fully characterize the Devonian Shale deposits and to improve the ability to recover the hydrocarbons from the deposits, several important parameters must be identified. These include the relative hydrocarbon abundances, the total amount of organic matter present, the predominant type, and the time-temperature (maturity) history experienced by the organic matter.

Currently, samples of the shale core are collected at the well site. These samples are analyzed in the laboratory for methane content, wet gas (C_2-C_4) concentration, gasoline-range hydrocarbons (C_4-C_7), kerosene-range hydrocarbons (C_8-$_{14}$), and the C_{15}+ hydrocarbons. In addition to these analyses, organic carbon determinations, visual kerogen isolations, and vitrinite reflectance determinations are also made. These data are then integrated to describe the richness, type, and thermal maturity of the source rock. The richness of the source rock is the total organic carbon content of the rock. This would include the insoluble organic material (kerogen) and the soluble (bitumen) matter. The type of organic source can be expressed as wet gas (high C_2-C_4) concentrations, oil, gas, or condensate precursor. The thermal maturity reflects the temperature history to which the organic matter has been subjected and indicates the nature of the hydrocarbons which will be available in reservoir traps in an area.

The C_1-C_4 hydrocarbons are determined in a two-step process. Initially, the sealed can is gas tapped, and the amount of gas which has evolved from the shale sample is determined. The sample is then macerated under water and the gas released during the process is determined. This process provides three data points: headspace gas, gas in rock, and total gas. The total gas value represents a minimum value, since some of the gas is evolved from the core during the time interval between removal from the core barrel and sample canning. This period averages between one and two hours.

Thermal chromatography is also being used to determine total hydrocarbon yield from the samples. The hydrocarbons evolved by thermal chromatography are identified by high resolution gas chromatography.

A modified material balance assay is also being performed on the samples to provide not only information on the oil yield but also the non-condensable gases released during the pyrolysis process. The modified assay provides information on the volumes of oil, non-condensable gases, and the water released during the pyrolysis process. Detailed analyses are being performed on the oil product and the gases.

Pulsed NMR techniques are also being applied to the Devonian Shales. These techniques are presently being evaluated as a rapid and accurate means of assaying oil from the western oil shales, the companion being that the FID amplitude is related to the hydrogen content of the oil shale, and the hydrogen content is indicative of the oil assayed from the shale by conventional Fischer Assay techniques.

We are attempting to evaluate methods of identifying the entire fuel (gas and oil) yield of the Devonian Shales. The total hydrogen and carbon content of the shale samples is being statistically correlated with the actual fuel (gas and oil) yield obtained from the material balance assay and total gas evaluations of the shale. These correlations will provide statistical regression lines from which potential fuel(gas and oil) yields can be estimated from future routine pulsed NMR evaluations.

Proton relaxation time studies are being conducted to establish the distribution of the various chemical species and their physical state in representatiive samples. Detailed evaluation of the relaxation times is being used to separate possible contributions of inorganic protons (i.e., adsorbed water, mineral hydrogens, tightly bound "dry" water, etc.) from the organic material.

In addition, the temperature dependence of relaxation times between 100K and 500K is being determined. The studies of the 300K-500K range are determining the loss of various inorganic and organic components from the shales, while studies in the 100K-300K range are being used in an attempt to estimate the presence of solid, liquid, and gaseous components. For a given nuclear species, the spin-spin relaxation time decreases and the spin-lattice relaxation time increases when the component behaves as a rigid solid at low temperatures. Each physical phase has a characteristic temperature at which the spin-lattice relaxation time reaches a minimum and the spin-spin relaxation time reaches a constant minimum at a low temperature.

MECHANICAL TESTING

The mechanical testing program is designed to determine the rupture characteristics of the shale and the amount of gas released as a result of various loading parameters. The mechanical properties of the shales should be significantly influenced by both the gas and kerogen resources present in the shales.

The resources present in the shale samples affect not only the degree of fracture per load but also the crack front movement through the shale. As cracks propagate through the shale, a certain amount of gas will be released. To aid in fully characterizing the shale, not only the mechanical properties of the samples but also the amount and species of gas released as a function of loading are being determined.

Shale samples which have been characterized geochemically are placed in an environmental chamber coupled to a tensile tester. The sample is loaded in diametral compression; and as it is put under a steadily increasing load, the chamber pressure is monitored and a quadrupole mass spectrometer linked to the system provides a continuous read-out of the gas species present in the chamber.

The sample matrix currently being evaluated includes as-received samples and samples exposed to various relative humidities for extended periods of time. This latter condition is designed to determine the effects of hydration on the mechanical properties. Another variable that is being considered for the future is the exposure of the shale to fracturing fluids prior to testing.

The breaking strength of the as-received samples has varied from 0.92 MPa to 3.27 MPa. These values are being related back to organic content, gas released during fracture, and even more basically, the shore hardness value of the sample.

Dilatometry studies are also being performed on the shales. In these studies, the samples are placed in contact with a fracturing fluid and the linear expansion of the sample as a function of time is recorded by using a LVDT coupled to a digital recording device. The fluids which are being studied include water, kerosene, water and 2% $KC\ell$, and methanol and 70% (water and $KC\ell$).

SEM, SIMS, AND EDXRA

The Scanning Electron Microscope, Secondary Ion Mass Spectrometer, and Energy Dispersive X-Ray Analyzer are being used to provide a rather complete characterization of the samples. The SEM with its various modes of operation is providing an insight into the physical characteristics. It is being used to identify and distinguish the materials present in the samples, and to determine compositional distribution and phase boundary features.

The SEM does provide a new dimension for the petrographer as Figures 1 through 4 illustrate. Figure 1 shows how mineral and organic matter appear on the SEM. The organic matter (O) almost appears transparent; this is in contrast to the thin section/optical microscope view in which it would appear black. Figure 2 is a top view of a bedding plane showing a uniform distribution of spores. Figures 3 and 4 are SEM views of spores. The spore in Figure 4 has been fractured, and a center layer of pyrite is evident.

The Energy Dispersive X-Ray Analyzer is used to identify bulk elemental composition, particular structures, and anomalous features. Using thin section, it is possible to quantitatively identify matrix material, since the unit is linked to a mini-computer which quantitatively evaluates the spectrum.

The Secondary Ion Mass Spectrometer is being used to provide analysis of characteristic portions of the material. Using the ion gun of the system, it is possible to etch the sample while it remains in the SEM.

Figure 5 shows two typical spectra observed on a mineral lens that ran through a shale sample. Spectrum A was observed when the ion beam was focused on the center of the lens. Spectrum B was observed when the beam was focused on the edge of the lens. From Spectrum B, it can be seen that gas which was trapped at the lens/matrix interface was liberated during ion etching. With the focusable ion beam, it is possible to distinguish differences in organic material as well as more completely identify the inorganic material which is present.

In addition to basic characterization studies, these three instruments are also being used to evaluate the fracture surfaces of the mechanical test specimen.

PERMEATION

A specially designed permeation cell will be used to determine the permeation effects of pure gases and mixtures through the shale. The permeability of these gases will be determined as a function of pressure, temperature, and flow direction (parallel and normal to the bedding direction).

Another variable that will be explored will be the effects of water and other fracture fluids on the permeation of the gases through the shale.

RADIONUCLIDE STUDY

A radionuclides study to determine the concentrations of ^{238}U, ^{234}U, and ^{222}Rn will provide data that can be used to evaluate the environmental impact and health risk that would exist if concentrations of radioactive materials were released as a natural consequence of the hydrocarbon recovery process. Shale samples will be routinely analyzed for ^{222}Rn which, since it is a gas, would have the greatest environmental impact and health risk in a gas recovery process.

DATA ANALYSIS

All of the data generated from the above studies will be statistically analyzed. These analyses will be used to correlate the hydrocarbon content of the shales with their various secondary characteristics. It will be through these types of analyses that the ultimate gas potentials of the shales can be related to specific secondary characteristics. One of the goals of this analysis will be to evaluate the effectiveness of simplified methods of resource assessment using secondary characteristic identifications.

The approach to the data analysis is to model subunits that can be subjected to some degree of experimental closure before attempting to establish a relationship among fuel yield, analytical techniques, and shale characteristics. These subunits are based on both theoretical and empirical relationships. Experimental data are playing a dominant role in deciding the directions of the data analysis and are permitting objective decisions to be made on that part of the theory that is under test.

Important consequences of this data analysis are: an objective evaluation of the most accurate and reliable analytical techniques; possible methods of associating fuel content with the secondary characteristics of the shales; and a data bank which can be used for future evaluation and modeling studies.

SUMMARY

This has been a brief outline of the Eastern Gas Shale Project which is in progress at Mound Laboratory. We are currently in the process of evaluating core samples from five wells located in the Appalachian and Illinois Basins. Some of the results from these analyses are addressed in another paper published in the proceedings of this conference, and the oral presentation will cover the other results currently available.

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Figure 1. - *Organic and Inorganic Material Present in Shale.*

Figure 2. - *Spores Distributed Along Bedding Plane.*

Figure 3. - *A Collapsed Spore Located in a Shale Sample.*

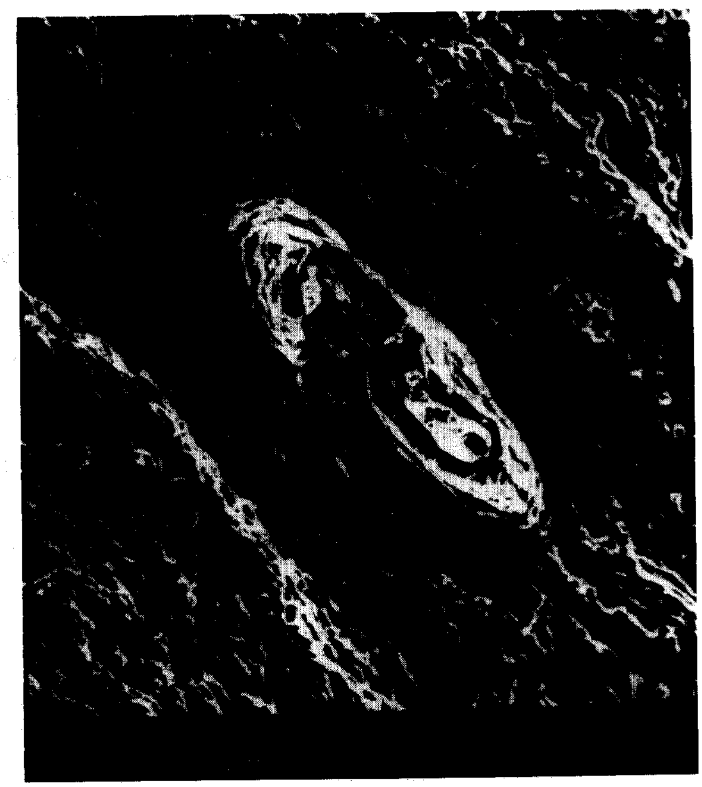
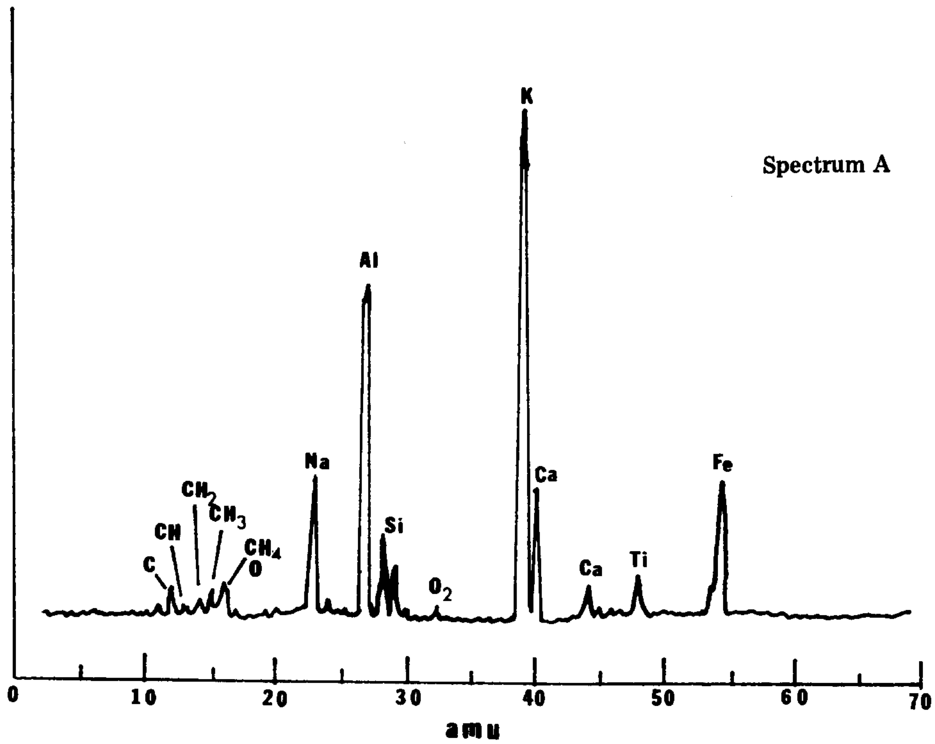


Figure 4. - *A Collapsed Spore With Pyrite Located in the Center.*



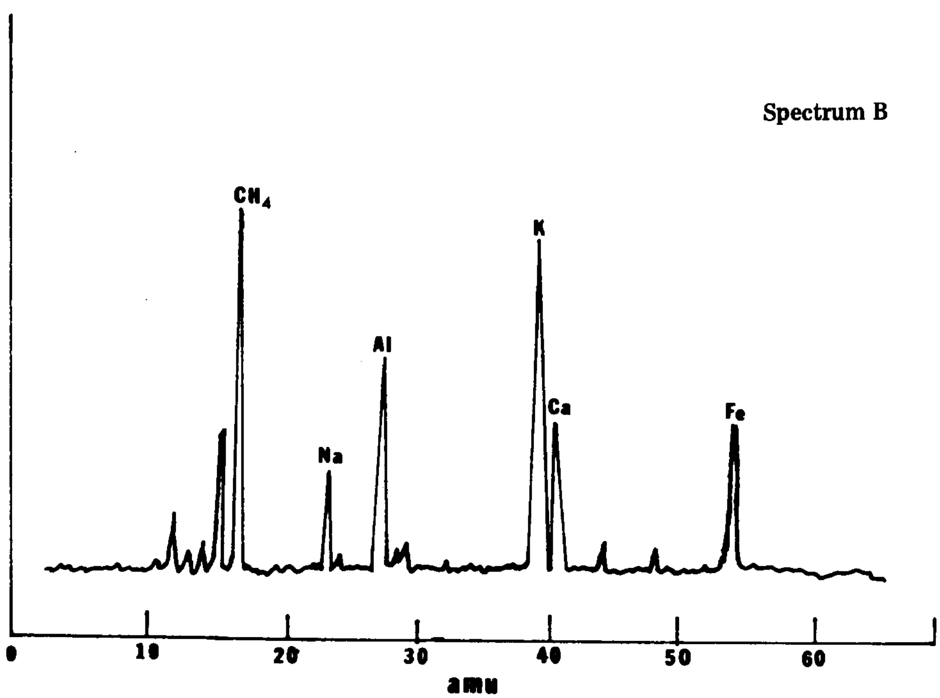


Figure 5. - *SIMS Spectra.*

INVESTIGATION OF STIMULATION TECHNOLOGY ON TIGHT GAS RESERVOIRS OF THE EASTERN UNITED STATES

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ABSTRACT

A joint Columbia Gas-USERDA project, aimed at testing stimulation technology in various Appalachian Basin sandstones and shales, is currently being conducted. Its purpose is to ascertain whether massive hydraulic fracturing (MHF), dendritic fracturing (Kiel), or cryogenic fracturing techniques would substantially increase gas production in the reservoirs treated.

This hydraulic fracturing program involves 13 wells and 14 fracturing treatments in five different producing reservoirs in several Appalachian states. The scope of the project includes the investigation of four dendritic fracturing treatments, four cryogenic treatments (in the Shales only) and six MHF treatments.

Since the onset of this project, three MHF treatments and one dendritic fracturing treatment have been performed. Two of these MHF treatments and the dendritic fracturing treatment were performed in the Clinton sandstone in northeastern Ohio. The third MHF treatment performed was in the Berea sandstone in western Virginia.

When this project is concluded, the results of these tests can be used for a comparative assessment of the effectiveness of the various treatments conducted.

INTRODUCTION

In an effort to meet the increasing demand for natural gas, Columbia Gas and the U.S. Energy Research and Development Administration (USERDA) initiated a project in July, 1976 to investigate enhanced gas recovery from marginal gas producing formations in the eastern United States.

The objective of this project is the investigation of the technical and economic effectiveness of hydraulic fracturing stimulation technology in various Appalachian Basin sandstones and shales. This project has obvious near-term goals and if successful, the effective technology could be applied to all producing areas in the Appalachian Basin and perhaps lead to a major expansion of drilling activities for natural gas.

Prepared for ERDA under Contract No. EF-76-C-05-5303

This paper presents this project, which will be concluded in 1978, and the research and field operations that have transpired since its initiation.

SCOPE OF PROJECT

This joint cost-sharing Columbia Gas-USERDA project is aimed at testing the effectiveness of various hydraulic fracturing treatments involving 13 wells in five different gas-producing formations in the Appalachian Basin. The project activities will include the investigation of six massive hydraulic fracturing (MHF) treatments, four dendritic (Kiel) fracturing treatments and four cryogenic fracturing treatments. The five geologic formations which are scheduled to be tested in the project and which involve the following criteria are (not in order of priority):

Clinton Sandstone (Ohio) - two retreatments (both MHF) and two new wells (one MHF, one dendritic)
Berea Sandstone (Virginia) - two new wells (one MHF, one dendritic)
Benson Sandstone (West Virginia) - two new wells (one MHF, one dendritic)
Oriskany Sandstone (West Virginia) - two new wells (one MHF, one dendritic)
Devonian Shales (Kentucky, Ohio, West Virginia) - three new wells and one dual completion well (all cryogenic).

Thus, this program will involve 14 stimulation treatments in 13 wells in four Appalachian states. Stimulation with the MHF techniques will utilize at least 200,000 gallons of fluid per treated interval. In the designs where dendritic or cryogenic treatments are planned, the volumes of the fracturing fluids used will be developed based on the physical factors of each formation involved. Also, all of the treatment designs are to be based on monetary cost parameters.

The new wellsite locations for the project are planned to be in areas of increased fracture trace density or near surface lineaments that can be mapped from available radar, U-2 or Energy Resource Technology Satellite (ERTS) imagery, so that gas containing natural fracture systems may be encountered for enhanced gas recovery.[1,2]

WELLSITE SELECTION

Figure 1 is an example of selecting the new wellsites for the project. These new wells will be selected in proximity to the regional fracture systems so they intersect fractured zones of concentrated gas accumulations in the reservoirs investigated.

When remote sensing imagery (radar or U-2 or ERTS) is studied, distinct lines (lineaments) can be found on it and wells can be spotted so as to intersect the zones of fracture porosity (gas-containing zones) in the reservoir associated with these lineaments.

The procedure is to review the available imagery of the general area for the well and delineate surface fractures (illustrated as lineaments on the imagery). These lineaments are then transferred from the imagery photo to a 7½ minute quadrangle topographic map with a Bausch and Lomb zoom transfer scope, which allows proper scaling of these lineaments to the topographic map. Once transferred to the topographic map, more definitive locations of these lineaments can be pinpointed. Field measurements of the strike (azimuth) and dip (expression of the angle that the feature makes with the horizontal plane) of the surface fractures can then be made. With these measurements, a well can be selected in such a manner as to intersect the zones of gas containing natural fractures in the reservoir with a simple geometric equation (assuming these surface expressions are consistent to the reservoir of concern). As shown in the example of Figure 1, 554 feet of displacement from the surface expression (lineament) on the dipping side of the surface fracture is needed to spot the well to intersect the natural fracture system in the reservoir. Of course, adjustments on the surface for topographical features have to be made in almost all cases; however, proximity to these surface fractures must still be maintained to intersect their components in the reservoir.

WELLS SELECTED

As illustrated in Figure 2, ten of the proposed 13 wells for the program have been selected. Six of these wells (two shale wells in Kentucky, one shale well and one Berea well in Virginia, and two Benson wells in West Virginia) were based on the above criterion of selection near surface lineaments. The remaining four Clinton wells (in Ohio) were not based on surface lineament studies because of glacial deposits overlying the terrain and obstructing imagery manifestations. Instead, these four wells were selected based on known Clinton production in their respective areas in Ohio.

Also illustrated in Figure 2 is the general location of three proposed wellsites yet to be selected for the program.

DRILLING AND CORING OPERATIONS

Table I presents the project wells that have been drilled. Also, their locations, target zones, and total depths are illustrated. As shown, four new wells have recently been drilled (based on remote sensing imagery studies) for the project, and four additional wells were drilled but not stimulated prior to the program's inception.

Accordingly, in an attempt to more fully characterize the geologic formations being investigated, cores of each formation are to be obtained and examined. The formations that have been cored, and the interval of core extracted from each, are also included in Table I. Not illustrated in this table is 60 feet of Berea sandstone core that was obtained from a well in Buchanan County of western Virginia. This well was drilled for the program but had to be abandoned because of the splitting of the casing and tubing which occurred when the tubing was removed when preparing for a reservoir test.

In summary, eight of the 13 wells in the program have been drilled with four drilled prior to the program's inception, and four specifically selected with remote sensing techniques for the program goals. The remaining five wells to be drilled will also be based on remote sensing imagery studies in their respective areas. Two wellsites in Upshur County in north-central West Virginia have just recently been studied and selected. Drilling operations on these two wells should be completed in the forthcoming months. Lastly, two of the five geologic formations being investigated (Berea Sandstone and Devonian Shale) have been cored for characterization and resource delineation studies.

LOGGING OPERATIONS

To supplement core information and to select specific zones for stimulation in each well, a conventional logging program will be used. The gamma ray log, the sibilation log, the resistivity log and the temperature log were the logs primarily used to delineate the gas-bearing zones. Future zone delineation for the other project wells will also use these logs.

ASSOCIATED RESEARCH

In addition to Columbia Gas, other organizations are also participating in this 13-well test program. Figure 3 is presented to illustrate the functions of these organizations. As shown in the Figure, most of these organizations are involved in core studies of the five geologic formations being investigated. For instance, of the cores extracted thus far, intervals were submitted to the Morgantown Energy Research Center (MERC) of ERDA for orientation (to collaborate natural fracture orientation) and directional property analysis. Also, specimens were removed at the well site for degasification studies by Columbia, Battelle and others. Additional specimens were removed for fracture mechanics tests by the Service Companies and Terra Tek of Salt Lake City, Utah and also, specimens were submitted to the United States Geological Survey (USGS) of Reston, Virginia, Mound Labs of Miamisburg, Ohio and Juniata College of Huntingdon, Pennsylvania for geochemical studies (gas maturation analyses). For the reservoir-property analysis, specimens were sent to Core Lab of Dallas, Texas. Future cores extracted will also be submitted to these organizations for further resource and reservoir property delineation.

STIMULATION TREATMENTS PERFORMED

To illustrate the volumes of fluid and sand used in the various treatments performed, Table II is presented. Also, the physical treating parameters are presented for illustration.

The first well hydraulically fractured under this contract with the USERDA was Columbia Well No. 20237 in the Clinton sandstone in Mahoning County of northeastern Ohio. This treatment was conducted in August, 1976. The design used was that of the patented Kiel (dendritic) fracturing process in which 106,000 gallons of gelled (guar gum) water and 40,000 pounds of sand (25,000 pounds of 80/100 mesh and 15,000 pounds of 20/40 mesh sand) were injected at an average rate of 52 barrels per minute (BPM) in five successive injection/flowback periods. Also injected, for an energy-assist mechanism, was 425 Mscf of carbon dioxide.

As illustrated in the Table, the average fracturing pressure reached during this Kiel treatment was 2,600 psig; with the maximum treating pressure attained 2,800 psig. The instantaneous shut-in pressure (ISIP) recorded immediately after the treatment was 500 psig.

The second stimulation treatment performed in the project was a massive hydraulic fracturing (MHF) retreatment conducted in September, 1976 in a Clinton sandstone section in Columbia Well No. 11236 in Trumbull County of northeastern Ohio. The zone in this well had been previously treated in August, 1972.

This first hydraulic fracturing treatment of this zone (4,566 feet - 4,639 feet) utilized 50,400 gallons of a gelled water fluid carrying 61,800 pounds of 20/40 mesh sand. The treating pressure during this "conventionally" sized treatment averaged 2,300 psig and the initial breakdown pressure was 1,850 psig. The maximum pressure reached during the pumping of the fluid and sand was 2,700 psig. The ISIP following this first treatment was 1,100 psig and after a five-minute shut-in period, the pressure had dropped to 825 psig.

The MHF retreatment, performed to extend the original fracture, utilized 324,580 gallons of gelled water with 500,000 pounds of sand (60,000 pounds of 80/100 mesh and 440,000 of 20/40 mesh sand) and 691,760 Scf nitrogen (injected continuously at approximately 100 Scf/Bbl throughout the treatment for energy-assist for faster clean-up).

As illustrated in Table II, the injection rates during the MHF retreatment of the Clinton sandstone started at 20 BPM and were increased to 40 BPM by the end of the treatment. Also, the sand concentration was peaked at four (4) pounds per gallon (ppg) of 20/40 mesh at the tail-end of the treatment.

The average treating pressure during this MHF retreatment was 2,200 psig and was only slightly higher (by 100 psig) than the average treating pressure of the "conventionally" sized treatment performed previously in this same zone. The maximum treating pressure that was attained during the MHF treatment was 3,100 psig. The ISIP after this retreatment was 1,800 psig and this pressure decreased to 1,050 psig after 15 minutes of shut-in. These pressure values were somewhat higher during and after this MHF retreatment than the earlier "conventional" treatment.

The third Clinton sandstone well treated thus far in the project was also in Trumbull County of northeastern Ohio. In November, 1976, another gelled water MHF treatment was conducted in the Clinton section in Columbia Well No. 20245. The Clinton in this well was perforated with 17 - 0.40-inch holes between 4,230 feet and 4,311 feet (refer to Table II). It was then stimulated with 334,000 gallons of gelled water with 600,000 pounds of sand (100,000 pounds of 80/100 mesh and 500,000 pounds of 20/40 mesh), and 695,250 Scf of nitrogen. Pumping rates during this treatment averaged 30 BPM. The sand concentration was peaked at 4 ppg of 20/40 mesh sand at the tail-end of the treatment. Originally, it was planned to peak the 20/40 mesh sand concentration at 3 ppg; however, during the treatment, the Clinton was taking sand so well that it was decided to emplace the 20/40 mesh sand at 4 ppg at the tail-end.

The average treating pressure during this MHF treatment of the Clinton sandstone was 2,400 psig and the maximum pressure attained was 2,960 psig. The ISIP following the treatment was 1,550 psig and after a ten-minute shut-in, the pressure declined to only 1,530 psig.

The last treatment conducted thus far in this program occurred in January, 1977, when a third MHF treatment was conducted in the Berea sandstone section in Columbia Well No. 20211 in Dickenson County, Virginia. The zone treated had been perforated with 21 - 0.40-inch diameter deep penetrating holes between 4,133 feet and 4,193 feet (refer to Table II). In this well, the Berea sandstone was treated with 285,600 gallons of gelled water with 555,000 pounds of sand (435,000 pounds of 20/40 mesh and 120,000 pounds of 80/100 mesh) and 762,500 Scf of nitrogen. The pumping rates were incremented from 20-40 BPM and the 20/40 sand concentration was peaked at 5 ppg at the tail-end of the treatment.

The average treating pressure during this MHF treatment was 1,400 psig and the maximum pressure attained was 1,800 psig. The ISIP following this treatment was 100 psig and after 15 minutes of shut-in the Berea went on vacuum (0 psig).

In summary, four stimulation treatments of the proposed 14 have been conducted. Three of these have been MHF treatments in two northeastern Ohio Clinton sandstone wells and one western Virginia Berea sandstone well. The fourth treatment conducted has been a patented Kiel (dendritic) fracturing process also performed in a northeastern Ohio Clinton sandstone well.

All three of the MHF treatments performed have utilized approximately 300,000 gallons of fluid pumped at an average rate of 30 BPM and emplacing 500-600,000 pounds of sand. Also, approximately 700 Mscf of nitrogen has been injected throughout these "massive" volumes for supplemental energy-assist for faster removal.

The Kiel process performed utilized only about one-half (½) the fluid volume (160,000 gallons) and one-fourteenth (1/14) the sand volume (40,000 pounds) as compared to the MHF treatments. However, these smaller volumes of fluid and sand were injected at a much higher rate (52 BPM). Also, the energy-assist mechanism was incorporated into the Kiel process by injecting carbon dioxide (425 Mscf) as compared to the use of nitrogen with the MHF treatment performed.

RESULTING PRODUCTION

Of the four sands stimulated, three have produced gas since stimulation. One Clinton sandstone well (Well No. 20245), even after extensive swabbing efforts to remove the frac fluid and promote gas production, continued to make salt water and therefore was plugged.

Table III presents the four stimulated wells, the formation treated in each and the type of treatment performed. For illustration, the initial open flow before the treatment and the average daily open flow after the treatment are given.

In all three of the treated wells where gas production has resulted, the daily open flows have increased after stimulation.

RESERVOIR TESTING RESULTS

To establish a criterion for comparison of the effectiveness of the treatments, pre- and post-treatment reservoir tests are to be conducted on each well to determine reservoir parameters before and after the treatment.

For Columbia Well No. 11236, a pre-MHF test was conducted during September, 1976. This well was drilled as a wildcat in 1972 in Trumbull County, Ohio, to a total depth of 4,743 feet. Completion was made in the

Clinton sandstone. In 1972, the well was "conventionally" fractured, as previously cited, and had been on production since December of that year. Originally, the well produced some oil and water; however, no oil has been produced since the beginning of 1976.

The pressure transient test conducted on this well prior to the MHF retreatment consisted of three drawdown-buildup cycles. Each drawdown period lasted four hours and was followed by a shut-in period of equal duration. Flow rate, and both wellhead and bottomhole pressures, were measured as a function of time by Columbia personnel. The well had been shut-in since early August, 1976, prior to opening the well for the first drawdown in September, 1976. During the pre-MHF test, no fluid production was measured at the surface and there was no evidence of fluid accumulation in the wellbore.

The primary objective of this pre-MHF analysis was to determine the reservoir permeability (k) and skin factor (S). This information would provide a comparison basis for post-MHF test results conducted after the treatment to indicate the relative success of the MHF stimulation on this Clinton sandstone. In addition to this, estimates of the induced fracture properties generated by the 1972 "conventional" treatment were desired for comparison to the induced fracture properties of the MHF retreatment.

Table IV presents the results of the pre-MHF test data analysis submitted by Intercomp Resource Development and Engineering, Inc. of Houston, Texas (reservoir engineering consultants subcontracted by Columbia for this project). In their analysis, Intercomp used both conventional plotting techniques and numerical simulation[3] to interpret the test data.

Since the test was conducted after the first conventionally-sized treatment and before the MHF retreatment, these results found in Table IV reflect the effects on the reservoir created by the conventionally-induced fractures conducted in 1973. For instance, according to the test results, the conventionally-sized treatment created a fracture 90.0 feet long (or 45 feet on a wing) with an infinite flow capacity (kh).

As of the time the paper was written, the post-MHF test of this well had not been conducted. This is due to the desire to let the flow stabilize from the Clinton sandstone and also, a scheduling problem encountered in treating the Devonian Shale zone further up the hole in this well (dual completion well). Therefore, a direct comparison cannot be presented at this time. The post-MHF test on this well is to be conducted by late August, 1977.

Also included in Table IV are the results of the post-dendritic treatment test results in Columbia Well No. 20237. This well was drilled during May and early June, 1975 in Mahoning County of northeastern Ohio to a total depth of 4,928 feet. A net gas pay of 63 feet was found in the Clinton sandstone. Core analysis of slightly over 50% of the pay averaged the horizontal permeability (k) at 1.28 millidarcies (md). Analysis of well logs indicated an average water saturation of 34.9% and an average porosity of 6.4%.

In August, 1976, the Clinton sandstone in this well was hydraulically fractured with a dendritic (Kiel)-frac process. Before this stimulation treatment, there was an insufficient volume of gas flow (refer to Table III) to perform a pre-treatment reservoir test. However, a post-treatment test, consisting of three drawdown-buildup cycles, was conducted to evaluate the improvement achieved by hydraulic fracturing.

This post-treatment test was conducted by Columbia and the data analyzed by Intercomp with a single-phase, three-dimensional, radial flow numerical simulator.[4] Their model accounts for pressure-dependent rock properties, wellbore damage, wellbore storage, crossflow and partial penetration. In conjunction with this numerical modeling, conventional and type-curve analyses were used to obtain initial estimates of reservoir and fracture properties. The final determinations presented in Table IV for Well No. 20237 were based on adjusted values which gave a satisfactory match of the model-calculated and measured pressures.

From the test analysis results, the Kiel treatment induced a fracture 310 feet long (or approximately 155 feet on a wing) into the Clinton sandstone with a flow capacity (kh) of 100,000 md.-in.

As mentioned, an accurate comparison of pre-treatment and post-treatment performance could not be determined since a pre-treatment test was not possible. However, it was felt by Intercomp that the minimum improvement achieved by the Kiel frac process could be estimated by assuming no skin damage existed before the treatment. Figure 4 presents such a comparison at a constant wellhead pressure (WHP) of 980 psig. The projected after-fracture performance in this graph was computed with the numerical simulator described above. The pre-frac performance was computed with a radial model with no fracture (Skin = 0). This projection shows a minimum three-fold increase in cumulative gas production due to fracturing after two years of production. However, because of the excessive estimated wellhead pressure used in the projection (980 psig) Intercomp was asked to recalculate the production based on 200 psig; which is currently the line pressure into which the well is producing. With this recalculated value, more realistic production figures will be obtained.

According to the project goals, a post-treatment reservoir test was conducted after the MHF gelled water treatment in the Berea sandstone in Virginia (Columbia Well No. 20211); however, at the time this paper was written, the final analysis was not available for presentation.

Lastly, reservoir testing of the Clinton sandstone well (Columbia Well No. 20245) in northeastern Ohio was not conducted due to the low flow rate before the MHF treatment performed on it, and due to the saltwater production after the treatment (refer to Table III).

SUMMARY

Since initiation of the joint Columbia Gas-USERDA project in July, 1976, ten of the 13 scheduled wells have been selected. Of these ten wells, eight have been drilled (either prior to the program's initiation or specifically for the program) and therefore have made target formations accessible for stimulation treatments. Also, two more wells have recently been selected with remote sensing techniques, and are to be drilled in the forthcoming months.

Of the eight accessible zones, four have been stimulated--three Clinton sandstones (in northeastern Ohio) and one Berea sandstone (in Virginia). Three MHF treatments and one Kiel frac process have been performed.

Since stimulation, two of the Clinton sandstones and the Berea sandstone have produced gas. In these cases, the production has increased after the treatments were conducted. The third Clinton sandstone stimulated did not have any gas production, but produced saltwater, and therefore was abandoned.

Reservoir test results of a Clinton sandstone well stimulated with a "conventionally" sized treatment in 1972, indicate that this treatment induced a 90-foot fracture into the Clinton. Post-treatment testing of the recently performed MHF retreatment has not yet been conducted for a comparison of the MHF improvement.

Other reservoir test results of another Clinton sandstone well stimulated recently with a Kiel frac process, indicate that this treatment created a 310-foot fracture into the Clinton.

Continued research is being conducted by Columbia Gas, USERDA and other organizations. The objective is to test the technical and economic effectiveness of hydraulic fracturing technology for enhanced gas recovery from five marginal gas-producing reservoirs in the Appalachian Basin, and also to characterize these reservoirs for future development.

NOMENCLATURE

A = horizontal displacement of well from surface fracture
B = depth of well to reservoir
Cot = cotangent of dip angle
CO_2 = carbon dioxide
h = height
ISIP = instantaneous shut-in pressure, psig
k = permeability, md
kh = flow capacity, md.-in. or md.-ft.
lb/ft = pounds/foot, weight
Mcfd = thousands of cubic feet per day (gas flow)
md = millidarcy = 1/1000 of a Darcy
md-ft = millidarcy feet
md-in = millidarcy inches
N_2 = nitrogen
ppg = pounds per gallon
psia = pounds per square inch, absolute
S = skin factor
Scf = standard cubic feet
α = dip of lineament
^{o}F = degrees, Fahrenheit
ϕ = porosity, percent

ACKNOWLEDGEMENTS

The author wishes to thank Gordon Owens for helpful discussions and the Columbia Gas System Service Corporation management for permission to publish this paper.

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TABLE I

DRILLED WELLS IN COLUMBIA-USERDA
13-WELL TEST PROJECT

Columbia Well No.	Location	Formation Investigated	Date Drilled	Total Depth (ft)	Cored Interval (ft)
20237	Mahoning County, Ohio	Clinton Sandstone	1975*	4,928	--
11236	Trumbull County, Ohio	Clinton Sandstone	1972*	4,743	--
20245	Trumbull County, Ohio	Clinton Sandstone	1975*	4,412	--
20211	Dickenson County, Virginia	Berea Sandstone	1976	4,275	--
20336	Martin County, Kentucky	Devonian Shale	1976	3,457	1,000
20337	Martin County, Kentucky	Devonian Shale	1976	3,602	--
20338-T	Wise County, Virginia	Devonian Shale	1977	5,740	400
11354	Coshocton County, Ohio	Clinton Sandstone	1972*	4,517	--

*Wells drilled prior to project inception.

TABLE II

VOLUME AND TREATMENT PARAMETERS
OF PERFORMED TREATMENTS
IN 13-WELL TEST PROJECT

Well No.	20237	11236	20245	20211
Location	Mahoning Co., Ohio	Trumbull Co., Ohio	Trumbull Co., Ohio	Dickenson Co., Virginia
Formation	Clinton Sandstone	Clinton Sandstone	Clinton Sandstone	Berea Sandstone
Perfed Interval (ft.)	4,725-4,840	4,566-4,639	4,230-4,311	4,133-4,193
Treatment Date	8/31/76	9/29/76	11/10/76	1/5/77
Treatment Type	Dendritic (Kiel)	Water MHF Retreatment	Water MHF	Water MHF
Treatment Volume (gallons)	106,000	324,580	334,000	285,600
Sand Volume (Lbs.)	40,000	500,000	600,000	555,000
80/100 mesh/ peak conc.	25,000/4ppg	60,000/2ppg	100,000/4ppg	120,000/2.5ppg
20/40 mesh/ peak conc.	15,000/4ppg	440,000/4ppg	500,000/4ppg	435,000/5ppg
Nitrogen Volume (Scf)	--	691,760	695,250	762,500
CO_2 Volume (Scf)	425,000	--	--	--
Avg. Rates (BPM)	52	20-40	30	20-40
Avg. Treating Press. (psig)	2600	2200	2400	1400
Max. Treating Press. (psig)	2800	3100	2960	1800
ISIP (psig)	500	1800	1550	100
ISIP/minutes (psig)	--	1050/15	1530/10	0/15

TABLE III

PRODUCTION RESULTING AFTER STIMULATION TREATMENTS

Well No.	Formation Treated	Open Flow before Treatment (Mcfd)	Type of Treatment Performed	Cumulative Gas Produced (MMcf)/ Days on Line	Average Open Flow after Treatment (Mcfd)
20237[3]	Clinton Sandstone	3.4	Dendritic (Kiel)	27.8/200	1,200
11236	Clinton Sandstone	40*	Water MHF Retreatment	10.4/209	150
20211	Berea Sandstone	84	Water MHF	30.5/43	2,054
20245	Clinton Sandstone	NMG[1]	Water MHF	0[2]	0

*Production into existing line

[1]No measurable gas flow

[2]Produced saltwater after MHF treatment - plugged and abandoned.

[3]Also produced 285 bbls. of oil since stimulation.

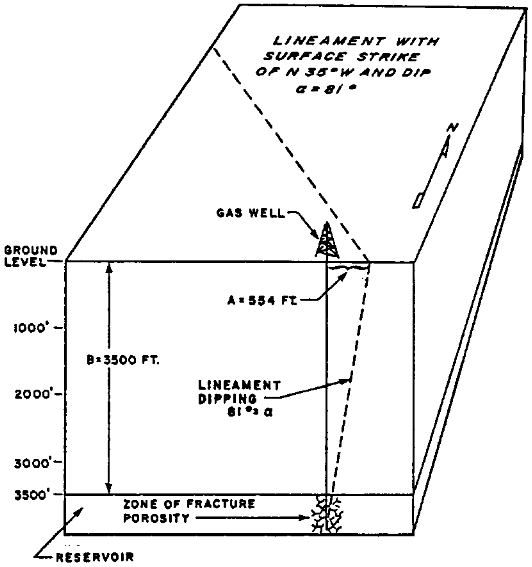
TABLE IV

RESERVOIR TESTING RESULTS

		Well No. 11236	Well No. 20237
Basic Reservoir and Well Data	Static reservoir pressure, psia	915.03	1624.25
	Formation net pay thickness, ft.	38	63
	Average total porosity, percent	4.8	6.4
	Estimated gas saturation, percent	71.1	57.9
	Estimated oil saturation, percent	5.5	7.2
	Estimated water saturation, percent	23.4	34.9
	Estimated reservoir temperature, °F	103	110
	Base temperature, °F	60	60
	Base pressure, psia	14.73	14.65
	Perforated interval, ft.	4566-4639	4725-4840
	Flow string diameter, in.	4.5	4.5
	Flow string weight, lb./ft.	11.6	11.6
	Estimated friction factor	0.013	0.013
	Well radius, ft.	0.328	0.342
	Well spacing, acres	160	160
	Test Performed	Pre-Treatment Test	Post-Treatment Test
Test Results	Initial drainage volume pressure, psia	915.03	1624.25
	Reservoir flow capacity, kh, md-ft.	10.26	9.639
	Pseudo-skin factor	-4.23	-3.70
	Net pay thickness, ft.	38	63
	Avg. res. perm., mds.	.270	0.153
	Avg. eff. gas ϕ, percent	.60	0.0347
	Post fracture flow eff., percent	--	360
	Reservoir turbulence factor, $ft.^{-1}$	--	7.020×10^{13}
	Turbulence factor in fracture, $ft.^{-1}$	1.40×10^{10}	1.521×10^{4}
	Fracture length, ft.	90.0	310
	Fracture flow capacity, md.-in.	(infinite)	100,000
	Fracture height, ft.	38	63

OFFSET OF WELL ON EARTH'S SURFACE TO INTERSECT FRACTURES IN UNDERLYING RESERVOIR

FIGURE 1



$A = B \cot \alpha$

WHERE:

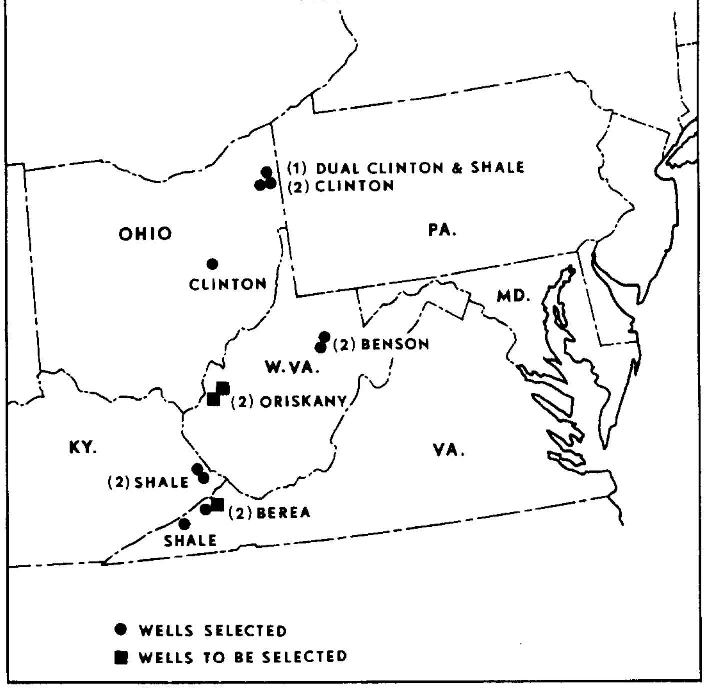
A = HORIZONTAL DISPLACEMENT OF WELL

B = DEPTH TO RESERVOIR

α = DIP OF LINEAMENT

PROPOSED WELL LOCATIONS FOR 13-WELL TEST PROGRAM

FIGURE 2



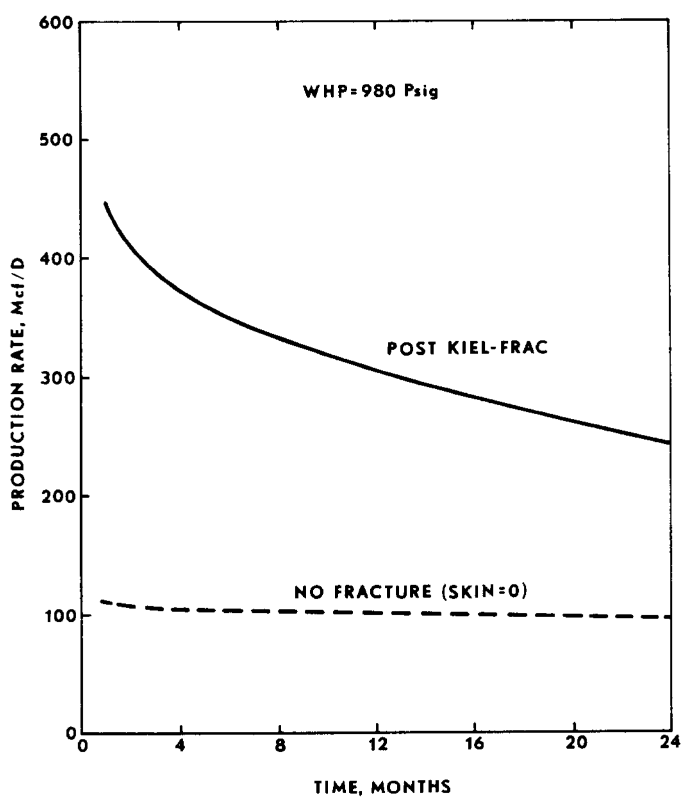
ASSOCIATED ORGANIZATIONS INVOLVED IN COLUMBIA GAS/USERDA 13 – WELL TEST PROGRAM

FIGURE 3

ORGANIZATION \ FUNCTION	Site Selection	Drilling	Coring	Logging	Core Studies	Rock Mechanics	Frac Design	Frac Execution	Frac Monotoring	Well Testing	Supply Materials For Treatment
Dowell					●		●	●			
Halliburton					●		●	●			
Other Kiel Consultants							●	●			
Intercomp										●	
Schlumberger				●							
Birdwell				●							●
McCullough Services				●							●
Ray Resources		●									
Aircowell							●	●			●
Battelle					●						
W. Va Geol. Survey					●						
Juniata College					●						
U.S.G.S.				●	●						
Terra Tek					●	●					
Christiansen Diamond			●								
Monsanto Mound					●						
ERDA-MERC	●				●		●				
Core Labs					●						
Oil Field Research					●						
West Virginia University					●						

PRE AND POST KIEL-FRAC PERFORMANCE COMPARISON CONDUCTED BY INTERCOMP FOR WELL NO. 20237

FIGURE 4



MASSIVE HYDRAULIC FRACTURING
OF THE DEVONIAN SHALE
IN LINCOLN COUNTY, WEST VIRGINIA

by

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ABSTRACT

Columbia Gas, in conjunction with the U.S. Energy Research and Development Administration (USERDA), is currently investigating the technical and economic effectiveness of massive hydraulic fracturing (MHF) techniques for enhanced gas recovery in the Upper Devonian Shales of the Eastern United States.

The project area includes three wells in a 5,000 acre undeveloped tract in western Lincoln County, West Virginia, approximately 40 miles southwest of Charleston, West Virginia. In each of these three wells, selected with remote sensing imagery for proximity to surface fractures (lineaments), the total depth encompasses the entire Upper Devonian Shale; a sequence which contains four primary zones of interest.

The scope of this joint Columbia Gas-USERDA investigation is to individually stimulate these twelve zones of interest with various MHF techniques. Since inception, five MHF stimulation treatments have been performed using foam and modified water in two of the wells. The third well is being reserved to utilize information learned from the first two.

Once complete, these ongoing tests can be used to assess the promise of large hydraulic fracturing treatments in stimulating these Shales and designing future treatments.

INTRODUCTION

The increasing demand for all energy forms and particularly natural gas has attracted attention from industry and the Government to explore new and large historic and nonhistoric sources of natural gas.

The thick, hydrocarbon-bearing Upper Devonian Shales (hereafter referred to as simply Devonian Shales), which underlie much of the Eastern States, have become a specific target of this exploration. The gas reserves locked in these shales, estimated to exceed by several times the current proven gas reserves of the nation, have made them a primary interest. Unfortunately, these shales, formed from muds deposited approximately 350 million years ago, are fine-grained with very low permeability; making it difficult to economically produce large quantities of gas from them to meet the natural gas demands.

Prepared for ERDA under Contract No. E(46-1)-8014

The objective of a jointly sponsored Columbia Gas-USERDA cost-sharing program, initiated in June, 1975 is to assess the technical and economic effectiveness of obtaining these large accumulations of gas with a stimulation technique known as massive hydraulic fracturing (MHF).

This paper presents this program, which will be concluded in 1978, and the research and field operations that have transpired since its initiation.

BACKGROUND OF PROGRAM

The purpose of this joint Columbia Gas-USERDA program is to determine if the Devonian Shales of the eastern United States can be given primary consideration for development of its gas reserves by unlocking them with massive hydraulic fracturing (MHF) treatments. Since the concept of MHF is based on existing knowledge employing existing field equipment, it represents an expedient technical solution to releasing these large gas reserves.

The scope of this program is to drill, core and log (for characterization) and stimulate, with MHF techniques, the Devonian Shales in three wells.

Based on past drilling around the proposed area for the program (Mingo, Lincoln and Wayne Counties of western West Virginia), it was estimated that the Devonian Shales in this test area range in thickness between 1,000 feet and 1,200 feet (refer to Figure 1). Therefore, due to physical factors, each MHF treatment could encompass about 250 to 300 feet of shale thickness and be about 250,000 gallons in fluid magnitude. The first well for the program, therefore, will be used as a MHF test-bed requiring a maximum of four (4) MHF treatments designed for effective treatment of each zone. The selection of these zones will be based on the physical limitations of the fluid and the knowledge gained from the coring and logging program on the reservoir rocks.

The intent of the second well in this program is to create fracture extensions from a smaller shale thickness zone. These smaller zones will be selected in regions of secondary porosity (natural fractures) in the Devonian Shales as found with core and log data. Historically, over 90 percent of all the wells drilled and stimulated (with 80% gelled nitroglycerine) in the Appalachian Basin Devonian Shales have produced gas. The better producing wells and the better producing areas of the Basin are believed to be associated with the occurrence of natural fracture systems.[1] The supposition with the selection of the MHF treatments in these zones of natural fractures is that, the induced MHF fractures will interconnect these gas containing natural fractures and increase the gas deliverability to the wellbore. In this second well, a maximum of four of these zones are to be hydraulically stimulated. Each treatment will cover up to 100 feet of shale thickness and will be on the order of 200,000 to 250,000 gallons.

The third well in the program will incorporate the results from the first two wells, which will provide design optimizations for the stimulation and target zone selections. For this well, a maximum of four 250,000 gallon treatments have been allocated.

This program, therefore, calls for twelve MHF stimulation treatments to be performed in the Devonian Shales in three wells selectively chosen.

CRITERIA USED FOR SELECTING THE WELLS

Since this program entails the investigation of a new technique in the Devonian Shales, Columbia Gas believed that the MHF program well sites would have to be close to an area of proven Devonian Shale production. This, it was felt, was the only way to allow a comparison of the new MHF technique's capabilities of increasing gas production. Also, this area selected would have to be near Columbia's gas gathering lines to allow extensive production testing to be done to make this comparison. The area chosen, based on these criteria, was the "Big Sandy" field of southwestern Virginia, western West Virginia and eastern Kentucky (also noted on Figure 1).

After the selection of this general area, the location of the three specific MHF program well sites was a particularly difficult task. The primary problem was to find a relatively undeveloped tract in the "Big Sandy" field suitable for potential MHF experimentation. Therefore, a relatively large, undrilled area for the wells would have to be found so that a maximum reservoir pressure would be encountered. This maximum reservoir pressure type of environment would denote a virgin area of the Devonian Shales, which would be, theoretically, indicative of other unproduced Devonian Shale areas in other parts of the undrilled Appalachian Basin. Therefore, it was believed that, with the use of this paradym, we could conceivably extrapolate the results from this particular area to other similar areas in the Basin. Another selection criterion for this tract in the "Big Sandy" field was that this area would have to be suited for the complicated logistics involved with MHF treatments. Since these treatments require a large number of pumping equipment and storage tanks, ample space for their placement was needed.

One last criterion that was set for the selection of the three wells in the "Big Sandy" field was that the area of their location have production indicative of a fractured reservoir. Traditionally, better producing Devonian Shale wells are thought to be associated with the occurrence of natural fracture systems,[2,3] yet, core samples of Devonian Shales previously taken by Columbia in the Basin, indicated that large quantities of gas were in close proximity to the wellbore (from off-gassing experiments). Therefore, it was conceivable that this matrix-bound gas could be produced through induced fractures. Columbia envisioned, with the use of this well site selection criterion, that MHF would offer an increased probability of communicating with the gas containing natural fractures and an increased efficiency of producing the matrix-bound gas through induced fractures for an enhanced gas recovery from the shales.

With considerable analysis of the available field data, three tracts were selected in the "Big Sandy" field based on the above criteria. Detailed production histories and special geologic maps were prepared covering a 36 square-mile range around each of these areas.

At the same time each of the three tracts were being analyzed for reservoir pressure, production and geologic data, Columbia was reviewing remote-sensing imagery in these areas. This imagery (primarily LANDSAT, with some U-2 and SKYLAB) was used to distinguish surface fractures (lineaments). The assumption in this analysis is that these surface expressions are manifestations of underground fracture patterns. With this imagery, the well sites were being selected in proximity to these surface lineaments to intersect the natural fracture systems downhole to fullfill the above criterion.

After analyzing this imagery data and field checking the three potential areas, an undeveloped tract in western Lincoln County, approximately 40 miles southwest of Charleston, West Virginia was selected for the location of the three test wells (Figure 2). This selected area was then submitted to the USERDA at the Morgantown Energy Research Center (MERC) in Morgantown, West Virginia for review. The three sites selected were approved and drilling operations commenced in early 1976.

PRELIMINARY FIELD OPERATIONS

Drilling of the first project well (Well No. 20403) began in early January, 1976. By the end of March, 1976, all three project wells were drilled and cased. The total depth of each well, which encompassed the entire Devonian Shales, were 3,920 feet (Well No. 20401), 4,066 feet (Well No. 20402) and 4,067 feet (Well No. 20403). The wells are located approximately one mile from each other.

The original casing program on all three wells consisted of approximately 80 feet of 13-3/8 inch surface casing, 2,500 feet of 9-5/8 inch intermediate string through the Berea sandstone, and approximately 4,050 feet of 7 inch production string casing to total depth. Due to cementing problems encountered on the first drilled project well, this original production string casing program for this well was modified. During the cementing operations of Well No. 20403, lost circulation occurred in the shale at approximately 3,780 feet. Therefore, to cement the rest of the shale, a two stage "air-balance" cement job was performed above this lost circulation zone. After these stages were completed, a squeeze cement job was attempted on the lost circulation zone. This treatment failed to seal-off the perforations in the zone, and 4-1/2 inch casing was run inside the 7 inch casing in order to perform the planned fracturing treatments below this lost circulation zone. Also modified was the original production string design for the remaining two wells (Well No. 20401 and Well No. 20402). In these wells, the 7 inch casing was changed to 5-1/2 inch casing to allow a thicker cement sheath behind the casing in the 8-3/4 inch drilled hole. This was done to preclude downhole casing problems, in case of abnormal pressures that might arise during the fracturing treatments.

In order to fully characterize the Devonian Shales for resource delineation and treatment design, Columbia felt it very important to core, in at least one well, the entire Devonian Shale column. Also, it was felt, this core should be supplemented with a complete suite of logs in all three project wells. Well No. 20403 was cored throughout the entire Devonian Shale column. In this well a total of 1,335 feet (from 2,720 feet - 4,055 feet) of shale was cored. The second project well drilled (Well No. 20401) was not cored due to the excessive shale thickness encountered in Well No. 20403; which was almost twice as thick as originally budgeted for. Lastly, the third project well drilled (Well No. 20402) was selectively cored for a total of 610 feet in the shales where additional detailed information was believed important (higher gas content zone). These high gas content zones were based upon off-gassing tests from the core taken in Well No. 20403.

All of the cores extracted from both wells were orientated every two feet for correlation to natural surface fracture orientation obtained from remote sensing interpretation. Coring time, with orientation, averaged about 100 feet every 24 hours. Stiff foam was used as the coring medium because of the apparent water sensitivity of the Devonian Shales.[4] With the use of this fluid, minimal problems were encountered.

After the respective wells were drilled and cored, logs were run for further Devonian Shale evaluation. The basic logging program for the three wells was designed around both dry-hole and wet-hole logs. The fluid used to accomplish the wet-hole logs was a 3% KCl water system with starch for fluid loss control. Table I illustrates the type of logs used in the logging program for the three wells. This suite of logs was run to more fully define the gas distribution and fracture distribution in the Devonian Shales.

Unlike the coring operations, problems were encountered with the shale breaking down when we attempted to load the entire hole with fluid during wet-hole logging operations. However, once fluid levels were maintained at approximately 2,100 feet, the shale stabilized and the wet-hole logs were able to be run with minimal problems.

ASSOCIATED RESEARCH INVESTIGATIONS

In association with Columbia Gas, other organizations have been incorporated into the MHF program. Figure 3 presents these other organizations and their functions in the program. It is beyond the scope of this paper to discuss their specific functions in any detail, however, in general, the majority of these organizations are involved in Devonian Shale core studies. These core studies include examining the cores for mineralogy, organic carbon content, trace element composition, maturation, physical properties (including rock mechanics), MHF design, etc. The final outcome of these investigations will be an assessment of the characterization and resource delineation of the Devonian Shales.

In conjunction with these organizations, Columbia is also performing core studies on the Devonian Shales. Our endeavors in these studies have centered around free-gas measurements of the shale (off-gassing experiments). As cores were pulled from the well they were preserved on location by sealing them in metal canisters and brought to the lab for free-gas measurements. After a few weeks in the lab, the diffusion of gas through these tight Devonian Shale cores became quite evident as the metal canisters started to deform from internal pressure. This phenomena was apparent in all the canisters (every fifth foot of core), denoting that gas was evolving from the entire shale column. The free gas released from these cores was then measured and these data are presented in Figure 4. From this graph it can be seen that all of the shale has some free gas evolving, with the higher values in the rich organic sections (black shales from lithology description). These results are very important from the standpoint of potential free gas reserve estimates and original gas in place estimates.

Figure 5 illustrates another aspect of the Devonian Shales Columbia has been involved with. This figure summarizes the geologic findings of the three Devonian Shale project wells, as prepared by Columbia's geologists. These cross-sections of each well were primarily based on log information, with some core information (as indicated) used to define the zones of vertical fractures. From the log analysis, the figure shows that six separate zones (Upper-Middle-Lower Gray Shales and Upper-Middle-Lower Brown Shales) exist in the Devonian Shales in the area of Lincoln County, West Virginia. Also, it illustrates that although these separate zones remain of the same thickness in the offset wells (approximately one mile apart) the gas distribution (from sibilation logs) and the vertical fracture distribution (observed from cores extracted) vary from one offset well to the other. This clearly demonstrated to Columbia the need and importance of a complete analysis of each Devonian Shale well in the program to enable selective stimulation treatments.

MHF TREATMENTS

Since this joint Columbia Gas-USERDA program began, five operationally successful MHF stimulation treatments have been performed in the Devonian Shales in two of the project wells. Rather than laboriously state the types and volumes of fluid and sand used in these treatments, Tables II (Well No. 20403) and III (Well No. 20401) are presented to illustrate these values along with other information found.

The procedures for performing each of these treatments included: evaluating the log and core information available for zone selection; perforating the zones as selected; breaking down the zones with HCℓ acid for wellbore damage removal; obtaining pre-treatment open flows; pre-frac reservoir testing the zones (to obtain initial values of flow capacity, reservoir pressure and assess wellbore damage); treatment design; execution and clean-up; obtaining after treatment open flows; and lastly, post-frac reservoir testing of each zone (to obtain final flow capacity, reservoir pressure and wellbore damage values to compare to pre-frac test values). Pertinent information found during these procedures is also listed in Tables II and III for each zone treated in the two wells.

In Table II, the volumes of fluid and the treatment application parameters found in three MHF foam type treatments performed in three separate zones in Well No. 20403 are illustrated. As mentioned earlier, the basic program called for the treatment of the entire shale column in one well; however, because of an excessive amount of shale encountered, 1,335 feet rather than the 1,000 feet anticipated, this plan was modified because of budgetary restrictions. Rather, the three zones treated (respectively labeled Zone 1, Zone 2 and Zone 3 in Table II) were selected based on log and core data depicting gas containment zones. The specific depths selected and perforated are given in Table II.

The use of foam as a fracturing fluid in Well No. 20403 came about after reviewing various frac proposals prepared by the Service Companies from both a technical and economic viewpoint. In view of the potential clean-up problems in this low pressure reservoir (found from pre-frac testing to be about 250 psi), it was decided to try foam-fracing because of its beneficial "energy-assist" mechanism by injecting gaseous nitrogen in the fluid. At the same time, it was also decided to use foam in the stimulation of all four zones in Well No. 20403. It was felt, by utilizing essentially the same frac fluid and the same design on all four zones, direct comparisons of production results with our in-place free-gas measurements from the cores could be accomplished. The volumes of foam used in these treatments were based on an approximate 1,000 gallons per perforated foot basis for each zone.

In Table III, the volumes of fluid and the treatment application parameters found in two types of MHF treatments performed in two separate zones in Well No. 20401 are illustrated. Since the basic program scheduled one well for treatments to extend induced fractures from a smaller treatment zone (100 feet) to intersect natural fractures, the two zones in this well were selected with this criterion from log information. Resistivity cross-plots (as illustrated in Figure 5) were used to determine the probable higher permeable zones; i.e., zones of natural fracture concentrations, which produce secondary porosity zones. The specific depths of the zones selected and perforated are given in Table III.

The first MHF treatment of the lowermost shale zone (Lower Brown Shale) in Well No. 20401 utilized a frac fluid consisting of gelled (guar gum) water. The choice of using a gelled water type treatment in the shales was based upon: (1) the need for a comparison of its effectiveness as measured against the results of the foam-type treatments and, (2) its present popularity with producers using it in other reservoirs throughout the industry, because of its attractive economics and past effectiveness. However, due to an excessive clean-up time experienced after this first gelled-water treatment (5 months to recover only 36% of the fluid used), the treatment type used on the second zone in this well (Middle Brown Shale) was modified. This second treatment included a foam spearhead component followed by a gelled water component, with nitrogen pumped throughout the treatment for an "energy-assist" mechanism for faster recovery. The volume ratio of the gelled water component to foam component was about 7 to 1. This type of treatment was labeled a modified water MHF by Columbia and its components are listed in Table III.

The sand schedule for the five treatments performed thus far utilized the injection of 80/100 mesh sand, to seal-off microfractures believed present in the Devonian Shales and thus minimizing fluid leakoff[5], followed by the injection of 20/40 mesh sand for maximum propped frac height. The volumes of sand and the peak concentrations, in pounds per gallon (ppg), emplaced in each treatment is given in Tables II and III.

Also included in Tables II and III are the clean-up times required for the frac fluid recovery of each treatment and the percentages recovered after these treatments. The most immediate effectiveness of a fracturing treatment that can be monitored for comparison is the clean-up time; that is, the amount of time after turnaround necessary for gas production. In the case of the treatments performed in the program, this time was cut-off when the gas was flowing free of fluid and also, the gas was flowing at a sufficient rate, without drowning out, to allow a constant terminal rate pressure analysis (on the order of 20 Mcfd because of flow gauge limitations). It may be mentioned here that reduced clean-up times are believed a necessity in the Devonian Shales because of the reduced relative permeability to gas created by the capillary retention of the imbibed fracturing fluids, and not necessarily a necessity because of clay problems (swelling and migration).

PRODUCTION RESULTS

For preliminary comparisons, measurements of gas volume open flows before and after the MHF treatments were obtained. It should be noted here that Columbia does not recommend using these "initial" pre- and post-frac open flows as indicators of the MHF's effectiveness on increased gas production, because of their inconsistent behavior in the Devonian Shales. Rather, based on past experience with the Devonian Shales, we feel a more reliable indicator is the use of decline curve analyses, in which gas production is monitored for at least three years to arrive at (by extrapolation) the potential production increases resulting from each treatment. However, in lieu of this, these "short-term" open flows obtained before and after each treatment do serve as indicators of the presence of gas in the shales or as we have recently found, as indicators of possible fracture communication in the shales. Therefore, these pre- and post-frac open flows will be presented for illustration.

For instance, in the project Well No. 20403, there was no measurable open flow before the MHF foam treatment on its first zone, which includes all of the Lower Brown Shale and a portion of the Lower Gray Shale (refer to Figure 5 for perspective of location in shale column). After the foam treatment, the total hydrocarbon flow rate rose to 110 Mcfd; after the production of the nitrogen used in the treatment ceased. Therefore, this open flow indicated to us that gas is present in these lower sections of the Devonian Shales, which in this portion of the Basin have never been a preliminary target for stimulation.

Upon perforating and breaking down the second zone in this well (Middle Brown Shale), an open flow of 95 Mcfd was measured. Due to this open flow's anomalous proximity to the first zone's open flow (110 Mcfd), a pressure interference test was conducted to investigate for communication (fracture migration) between the two zones. In conjunction with this pressure test, chromatographic composition analysis of gas samples obtained from both zones was conducted for comparison. Both the pressure interference test and the gas composition analysis showed communication between the two zones, as was originally indicated by the open flow. The evidences were a one-hundred (100) psig pressure drop within 24 hours in the untreated second zone, while producing the treated zone, and an identically high nitrogen concentration in both the gas samples analyzed from the treated and untreated zones. With these results, it was evident that the MHF foam treatment conducted on the first zone propagated some 199 feet vertically, into the untreated second zone. Therefore, during the MHF foam treatment on the second zone that followed, a diverting agent (benzoic acid) was used in the treating fluid to bridge-off the downward growth of the fracture into the lower zone already treated. The initial open flow recorded from this second zone after its treatment was 200 Mcfd.

Subsequently, the third zone in this well (including a portion of the Middle Gray Shale and all of the Upper Brown Shale) was perforated and broken down and an initial open flow of 103 Mcfd was gauged, which is substantially low enough that communication was not suspected. However, based on the experience of the lower zones, a pressure interference test and a gas composition analysis were conducted. Their results showed that communication wasn't present, indicating this open flow of gas to be "virgin" from this section of the shale. Nevertheless, as a safeguard, during the foam treatment of the third zone, a diverting agent was used to prevent fracture migration downward in the zones previously treated. As of the time this paper was written, this third zone was still cleaning up and approximately 30% of the water used has been recovered. The open flow after 17 days of clean-up was gauged at 111 Mcfd.

In the other project well (No. 20401), there was no measurable open flow prior to the MHF gelled water treatment performed on this well's first zone (Lower Brown Shale; also refer to Figure 5). After this treatment and an extended clean-up time of 7 months, the open flow was gauged at 110 Mcfd. Upon perforation and breakdown of the second zone (Middle Brown Shale), there was also no appreciable flow; leading us to believe there was no fracture induced communication between the two zones. Subsequently, a pressure interference test conducted reinforced this belief. At the time this paper is being prepared, the second zone was cleaning up after the modified MHF gelled water treatment was performed. Preliminary data show that approximately 57% of the fluid used for the treatment has been recovered after only 16 days. This is a markedly reduced return time of the fluid as compared to the lower zone treated in this well (5 months to return only 36%). The open flow after these 16 days was gauged at 119 Mcfd.

RESERVOIR TESTING RESULTS

In an attempt to define the improvement of the MHF treatments on each zone, pre- and post-frac reservoir tests were conducted to establish flow capacity (kh), permeability (k), skin effect (S) and effective fracture length ($2x_f$) for comparison. These tests consisted of approximately one week of drawdown (flowing the well at a constant rate) and two weeks of buildup (shutting the well in). The limiting factor for conducting these tests was a flow rate of no less than 20 Mcfd, because of the flow gauge restrictions.

These tests were conducted by Columbia, and the data obtained compiled and submitted to H. K. van Poollen and Associates of Littleton, Colorado (sub-contracted reservoir engineering consultants in the program) for their analysis. Table IV presents their test analysis results for the first two zones in Well No. 20403. Several types of analyses were used to calculate these results, which included the interpretation of linear, spherical and pseudo-radial flow regimes during the tests.

As illustrated in Table IV, pre- and post-frac data for the first zone in Well No. 20403 were not adequate because of a failure in the pressure recording device, and a complete analysis could not be performed. However, analysis of the flow test suggests the possibility of a permeability (k), in the range of 0.05 to 0.10 md after the treatment of this zone.

As mentioned earlier, interference testing indicated that the fracture generated by the first foam treatment migrated vertically into the second perforated interval (3,409 feet to 3,651 feet), resulting in communication between the sets of perforations. Therefore, the contributing interval during the pre- and post-frac testing of the second zone was not exactly known. In order to distinguish this uncertainty, van Poollen and Associates examined two limiting cases. Case I (as illustrated) assumes gas production during the testing was coming only from the second perforated zone (h = 205 feet). In Case II, they assume that the gas production is coming from both perforated zones and the interval in between (3,409 feet - 4,031 feet, h = 622 feet).

The results from the testing of the second zone show, from both cases, that the effective permeability, (k), of the portion of the shale reservoir investigated, is in the range of 0.03 to 0.44 md. Also, from the Horner plot of the pre-frac pressure test data, the negative skin effect (S) values of -4.3 (Case I) and -4.1 (Case II) indicate improvement of near wellbore conditions. These improvement indicators are probably due to the vertical extent of the fracture from the first zone moving up into this second zone and removing its wellbore damage. Also, after the second treatment, these wellbore conditions (S) were only slightly improved to -4.9 (Case I) and -4.75 (Case II).

Another important purpose of these test analyses is to determine the effective fracture length ($2x_f$) created by these MHF treatments. Once again, looking specifically at the Horner plot analysis, the pre-frac test data in Table IV indicate that the effective fracture length ($2x_f$) is 86 feet in Case I (flow from one zone only) or 72 feet in Case II (flow from whole interval between zones. Once again, these frac lengths probably represent the lateral extent of the first fracture in Zone 1. Subsequently, after the MHF treatment of the second zone, these effective frac lengths grew to 156 feet (Case I) or

136 feet (Case II), as illustrated by the post-frac test data. Accordingly this resulted in almost twice the effective surface area available for gas flow from the reservoir, in either case used. In the second zone, the observed increase in open flow, from 95 Mcfd before the treatment to 200 Mcfd after the treatment, reflects this increase in effective surface area. However, these effective frac length values obtained, according to the test results, are significantly lower than the predicted 760 feet from the Carter equation used by the Service Companies to determine the areal extent of a fracture.[6]

The test results for the third zone stimulated in Well No. 20403 and the two zones treated in Well No. 20401 were not available for presentation in this paper.

SUMMARY

Since the initiation of this Columbia Gas-USERDA program, three Devonian Shale wells have been selected using various areal topography and production criteria in Lincoln County, West Virginia. Also, these wells have been drilled, cored (selectively) and logged.

From the cores extracted, off-gassing experiments were performed which indicate free-gas is present throughout the entire Devonian Shale column in this geographic area. Continued research on the cores by Columbia and other organizations is being conducted for characterization and resource delineation of the Devonian Shales.

With the suite of logs run in the three project wells, cross-sections of the Devonian Shales in this geographic area have been prepared. These cross-sections depict six lithologically different sections (zones) in the Devonian Shales.

Based on the core and log data available, five zones in two wells have been selected and stimulated with MHF techniques. These zones in one well have been stimulated with the same fluid, namely, foam. The other two zones have been stimulated using gelled water in one zone and a foam-gelled water type in the other zone. Therefore, according to the basic program schedule, seven more zones have to be selected and treated; four of which will be previously found optimizations for use in the third well.

Production resulting from the zones stimulated thus far indicates that gas is definitely present in zones of the shale that have never been historically produced before. Furthermore, reservoir testing of two zones in one well indicates this production has resulted from vertical fractures extending laterally between 136 to 156 feet. This effective fracture length is on the order of five times smaller than predicted with the use of these massive volumes of fluid.

NOMENCLATURE

BPM = barrels per minute
h = height
ISIP = instantaneous shut-in pressure
k = permeability
kh = flow capacity
Mcfd = thousands of cubic feet per day (gas flow)

md = millidarcy
N_2 = nitrogen
ppg = pound per gallon
S = skin factor
Scf = standard cubic feet
Sg = gas saturation, in percent
x_f = fracture length on one wing
$2x_f$ = effective fracture length
ϕ = porosity, in percent

ACKNOWLEDGMENTS

The author wishes to thank J. Hook and R. Shrut for helpful discussions and the Columbia Gas System Service Corporation management for permission to publish this paper.

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DEVONIAN SHALE BASIN OF EASTERN UNITED STATES

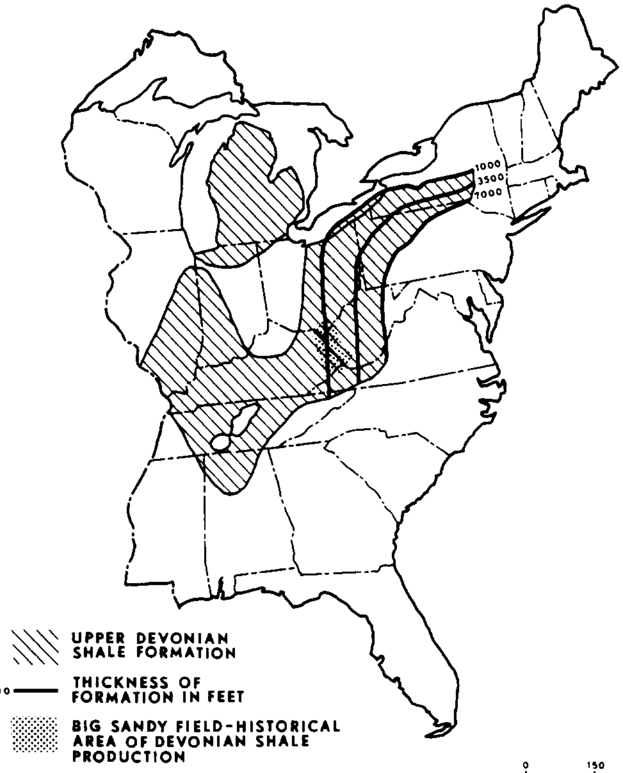


FIGURE 1

WELL LOCATION 3-WELL SHALE MHF TEST PROGRAM

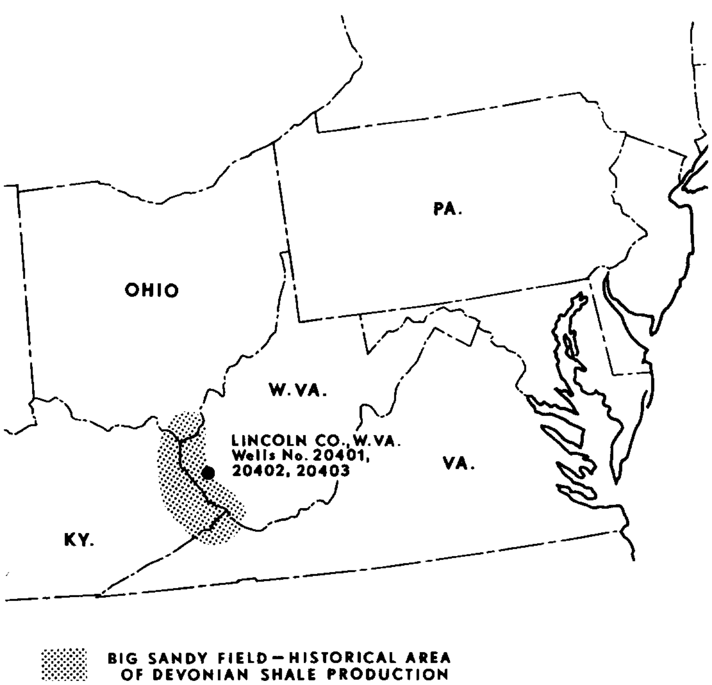


FIGURE 2

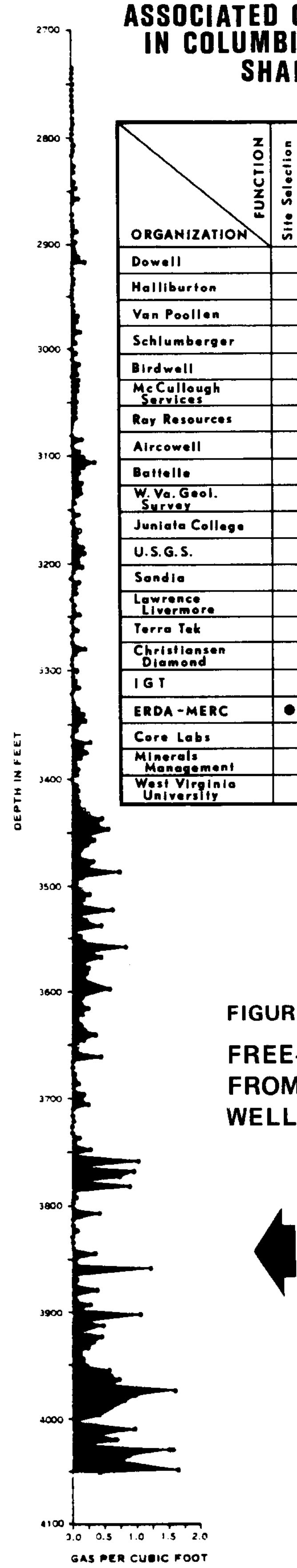


FIGURE 4

FREE-GAS MEASUREMENTS FROM CORES ON WELL NO. 20403

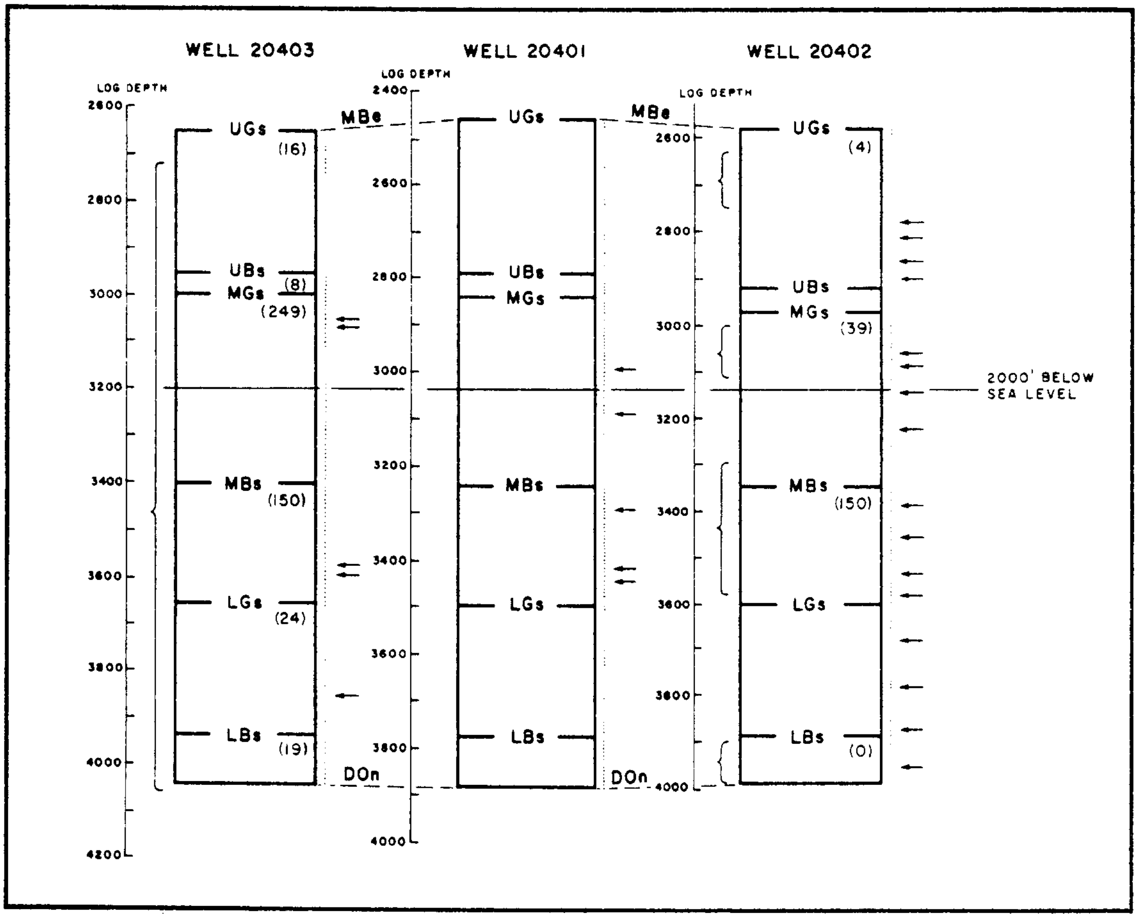
ASSOCIATED ORGANIZATIONS INVOLVED IN COLUMBIA GAS/USERDA DEVONIAN SHALE MHF PROGRAM

ORGANIZATION \ FUNCTION	Site Selection	Drilling	Coring	Logging	Core Studies	Rock Mechanics	Frac Design	Frac Execution	Frac Monotoring	Well Testing	Supply Materials For Treatment
Dowell					●		●	●			
Halliburton					●		●	●			
Van Poollen										●	
Schlumberger				●							
Birdwell				●							
McCullough Services				●							●
Ray Resources		●									
Aircowell							●	●			●
Battelle					●						
W. Va. Geol. Survey					●						
Juniata College					●						
U.S.G.S.				●	●				●		
Sandia									●		
Lawrence Livermore					●	●					
Terra Tek					●	●					
Christiansen Diamond			●								
I G T					●						
ERDA-MERC	●				●	●	●				
Core Labs					●						
Minerals Management							●	●			
West Virginia University					●	●					

FIGURE 3

SUMMARY OF GEOLOGICAL FINDINGS

(COLUMBIA MHF WELLS, LINCOLN CO., W.VA.)



LEGEND

MBe – BASE OF BEREA SANDSTONE

UGs – TOP OF UPPER GRAY SHALE AND SILTSTONE

UBs – TOP OF UPPER BROWN SHALE

MGs – TOP OF MIDDLE GRAY SHALE

MBs – TOP OF MIDDLE BROWN SHALE

LGs – TOP OF LOWER GRAY SHALE

LBs – TOP OF LOWER BROWN SHALE

DOn – TOP OF CORNIFEROUS (ONONDAGA) LIMESTONE

← – GAS SHOW FROM SIBILATION LOG

⁞ – PROBABLE PERMEABLE INTERVAL FROM RESISTIVITY CROSS PLOTS

(5) – FEET OF OBSERVED VERTICAL FRACTURES

{ – CORED INTERVAL

FIGURE 5

TABLE I

LOGGING PROGRAM FOR 3 TEST WELLS
IN COLUMBIA GAS/USERDA
DEVONIAN SHALE-MHF PROGRAM

Dry-Hole Logs Consisted of:	Wet-Hole Logs Consisted of:
Formation Density Compensated Log (FDC)	CORIBAND Series - Composed of Gamma Ray Log, Formation Compensated Density Log (FDC), Compensated Neutron Log (CNL), Compensated Sonic Log, Dual-Induction-Laterolog, and Microlaterolog
Sidewall-Neutron-Porosity Log (SNP)	3-D Velocity Log
Dual Induction Log	Seisviewer
Temperature Log - Absolute	Thermal Decay Time Log (TDT)
Temperature Log - Differential	
Sibilation Log	

TABLE II

VOLUME AND TREATMENT PARAMETERS
OF MHF FOAM FRACS
PERFORMED ON WELL NO. 20403

ZONE	ZONE 1	ZONE 2	ZONE 3
FORMATION	Lower Brown Lower Gray Shale	Middle Brown Shale	Upper Brown - Middle Gray Shale
PERFED INTERVAL (FT.)	3858-4031	3409-3651	2954-3230
TREATMENT DATE	6/21/76	11/15/76	5/23/77
TREATMENT TYPE/QUALITY	Foam/77%	Foam/81%	Foam/78%
TREATMENT SIZE (GALLONS)			
Foam	250,000	319,750	345,944
Water	58,480	59,750	62,270
SAND VOLUME (LBS.)	299,000	439,000	340,000
80/100 Mesh/Peak Conc.	19,000/1 ppg	29,400/1 ppg	60,000/3 ppg
20/40 Mesh/Peak Conc.	280,000/1.5 ppg	410,000/2 ppg	280,000/1.5 ppg
NITROGEN VOL. (Scf)	2,458,200	2,500,000	3,229,088
AVG. RATES (BPM)	37.5	40	9.6
AVG. TREATING PRESS. (PSIG)	1930	1550	1390
MAX. TREATING PRESS. (PSIG)	2250	1710	1480
ISIP	1950	850	1190
ISIP/MINUTES	1070/5 min.	770/5 min.	1150/5 min.
CLEAN-UP TIME (DAYS)	29	17	17*
% RECOVERED	44-water 52-N_2	14-water 80-N_2	30*

*Preliminary data

TABLE III

VOLUME AND TREATMENT PARAMETERS
OF MHF FRACS
PERFORMED ON WELL NO. 20401

ZONE	ZONE 1	ZONE 2
FORMATION	Lower Brown Shale	Middle Brown Shale
PERFED INTERVAL (FT.)	3788-3860	3272-3410
TREATMENT DATE	8/3/76	5/17/77
TREATMENT TYPE/QUALITY	MHF	MOD-MHF
TREATMENT SIZE (GALLONS)	517,014	104,076
Foam	---	12,642
Water	517,014	91,434
SAND VOLUME (LBS.)	930,000	319,326
80/100 Mesh/Peak Conc.	190,000/3 ppg	57,708/6 ppg
20/40 Mesh/Peak Conc.	740,000/3 ppg	261,618/8 ppg
NITROGEN VOL. (Scf)	120,000	794,000
AVG. RATES (BPM)	25.4	30
AVG. TREATING PRESS. (PSIG)	1758	800
MAX. TREATING PRESS. (PSIG)	5000	950
ISIP	1200	250
ISIP/MINUTES	250/15	0/5 min.
CLEAN-UP TIME (DAYS)	≈150	16*
% RECOVERED	36	57*

*Preliminary data

TABLE IV

RESERVOIR TESTING RESULTS
WELL NO. 20403

		CASE I*				CASE II*			
	TEST DESCRIPTION	kh md. ft.	k md.	Skin	x_f ft	kh md. ft.	k md.	Skin	x_f ft
Zone 1	Pre-Frac Flow Test		No Analysis				No Analysis		
	Pre-Frac Buildup Test		No Analysis				No Analysis		
	Post-Frac Flow Test	--	.05 → .10	--	--	--	.05 → .10	--	--
	Post-Frac Buildup Test		No Analysis				No Analysis		
Zone 2	Pre-Frac Flow Test								
	1/q Equivalent Plot	37	0.180	-2.60	8	37	0.059	-2.50	7
	Spherical Plot	29	0.140	--	--	68	0.110	--	--
	Linear Plot	--	0.179	--	22	--	0.088	--	9
	Pre-Frac Buildup Test								
	Horner Plot	22	0.109	-4.30	43	21	0.034	-4.10	36
	Spherical Plot	20	0.120	--	--	58	0.094	--	--
	Linear Plot	--	0.109	--	38	--	0.034	--	34
	Post-Frac Flow Test								
	1/q Equivalent Plot	91	0.445	-2.80	5	91	0.146	-2.70	8
	Linear Plot	--	0.130	--	306	--	0.042	--	290
		--	0.445	--	166	--	0.146	--	144
	Post-Frac Buildup Test								
	Log-Log Curve Match	66	0.320	--	142	66	0.106	--	124
	Horner Plot	26	0.128	-4.90	78	26	0.042	-4.75	68
	Spherical Plot	18	0.090	--	--	37	0.060	--	--
	Linear Plot	--	0.128	--	84	--	0.042	--	72

*Assumed ϕ = 2.438%; Sg = 77.3%; h = 205 feet
**Assumed ϕ = 1.804%; Sg = 45.8%; h = 622 feet

CHEMICAL EXPLOSIVE FRACTURING OF EIGHT TIGHT GAS WELLS

by

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ABSTRACT

The objective of this joint ERDA/industry program is to evaluate the potential of large chemical explosive loads (20,000 to 30,000 pounds) to stimulate and enhance recovery of gas from tight reservoirs. Six of the eight wells are in the Devonian Shale—three in Kentucky, three in West Virginia, and two are in the Canyon Sands of southwest Texas.

A general description of the on-site explosive manufacturing placement and detonation techniques is presented. Details of the preshot and postshot testing and production are given on wells stimulated to date. The program is continuing.

Prepared for the Energy Research and Development Administration under Contract Numbers EY-76-C-08-0685, EY-76-C-08-0686 and EY-76-C-08-0687.

Note: Copies of this report are available from the authors.

AMEX/VESCORP DEVONIAN SHALE PROJECT
LAWRENCE & SCIOTO COUNTIES, OHIO

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ABSTRACT

Amex/Vescorp in conjunction with U.S.E.R.D.A., Ohio E.R.D.A., and National Petroleum Corp., is conducting a field demonstration test to provide information on the Devonian Shales, in Lawrence and Scioto Counties, Ohio, which can be used in the immediate and surrounding areas to increase gas production from the shale.

The general objectives of this program are to establish the effectiveness of remote sensing imagery as a tool in picking shale well site locations, to determine the benefit of advanced stimulation techniques, and to determine if a scaled up version of the fracture technique deemed to be the better of the two above would be a cost-effective method of improving production rates and reserves.

Analysis of the remote sensing imagery was completed on May 24, 1977. Nine primary and twelve alternate well locations have been selected as a result of this work. The drilling of these wells will commence in the near future at which time coring and logging will be used to help determine which zones should be stimulated.

Prepared for the Energy Research and Development administration, under Contract No. E(40-1)-5253.

INTRODUCTION

The Devonian Shale underlies more than 100,000 square miles in the Appalachian area including such states as Kentucky, West Virginia, Michigan, Indiana, New York, Pennsylvania, Ohio and others. This Devonian Shale formation is the subject of much speculation because of large estimates of natural gas reserves. The U.S. Energy Research and Development Administration and the Ohio Energy and Resource Development Agency have both gone on record as estimating gas in place in the Devonian Shale to be in the quadrillions of cubic feet in the continental United States. The Ohio ERDA has estimated that with existing technology, seventy (70) trillion cubic feet of gas could be produced in Ohio alone.

Even with the impressive reserve estimates, the low field price for natural gas prevents the Shale from receiving any more than nominal attention from independent producers.

The potential of the Devonian Shale is not a newly discovered horizon of productivity. Several thousand wells have and are producing natural gas from Shale. Most shale wells in the Appalachian area are contained in the Big Sandy Field of Kentucky and West Virginia in addition to several Ohio counties such as Lawrence, Scioto, Meigs and Licking.

It is generally recognized that the average shale well will outproduce the average sandstone well in Appalachia, but it takes several decades for the shale production to occur. The economics favor sandstone over shale because of cash flow considerations related directly to rate of production. Independent producers are economically attracted to the lower gross production of the sandstone because of the more acceptable rate of return it provides. In contrast, while containing much larger recoverable reserves, the shale presently produces at so slow a rate of return as to deem it financially unacceptable. This generalization would be more aptly applied to less fractured shale areas such as found in Ohio than to the highly fractured Big Sandy Field of Kentucky and West Virginia.

The primary problem area with shale is stimulation. Shale is generally very tight, having porosities of 4 to 5%, or less. The consensus of opinion for Appalachian Shale is that large production is a direct result of communicating with natural fracture systems either in the drilling operation or through stimulation. Therefore, if a well can be drilled into a natural fracture system and then be efficiently stimulated, economics resembling sandstone wells will hopefully result.

The initial stimulation of Devonian Shales consisted of employing liquid nitroglycerine to explosively stimulate a small zone of the borehole. The zone of stimulation was usually no greater than 50 feet in thickness. The Shale section becomes several thousand feet thick in some areas of the Appalachian Basin. Liquid nitroglycerine proved very dangerous to use over a large interval.

Eventually liquid nitro gave way to black powder and desensitized nitroglycerine. The majority of shale wells have been treated with 80% gel which is desensitized nitro. This form of stimulation allowed producers to treat thick zones of shale at a time. Zones as thick as 1200 feet have been treated with 80% gel.

The introduction of hydraulic fracturing in the Appalachian Basin eventually led to a comparison between "shooting" 80% gel and "water fracing" in the shale. Kentucky West Virginia Gas Company and others have compared these two stimulation methods in similar shale areas and have generally concluded that hydraulic fracturing with water was superior to shooting.

In recent years, several revolutionizing concepts in stimulation have been examined in the Devonian Shale. The U.S. ERDA, Columbia Gas System Service Corporation and others have examined stimulation methods such as stiff foam, cryogenic fracs, and liquid explosives. Results to date do not appear conclusive regarding the merits of these new concepts in stimulation because of a limited number of treatments for each type of stimulation and little direct comparison between the new stimulation techniques in the same shale field.

This proposal seeks to make a direct comparison between stiff foam stimulation and cryogenic stimulation in Lawrence and Scioto Counties, Ohio. The State of Ohio has considerable shale history but very little in the way of new stimulation techniques have been examined in Ohio Shales. None of the new methods have been employed in Lawrence and Scioto Counties which have been the most prolific shale production areas in the State.

In addition to direct stimulation comparison, the program proposes to provide information concerning the Devonian Shale in Southern Ohio that is presently not available. Although many shale wells have been produced in the subject area, very little is known about the stratigraphy or physical properties of this shale.

Figure 1 indicates the townships from which productive shale wells have been recorded in the State of Ohio. The target area for this program is circled.

PROPOSED PROGRAM AND OBJECTIVES

The general objectives of the proposed program are to identify natural fracture systems in the shale by use of remote sensing imagery and also to establish the quantitative benefit of advance stimulation techniques compared to historic stimulation techniques in the Ohio Devonian Shale. The historic stimulation treatment in Southern Ohio has been nitroglycerine or desensitized nitroglycerine. The proposed program will evaluate the effectiveness of stiff foam and cryogenic fracturing.

The initial period of the program will be concerned with geologic study of the area including the interpretation of the available well information and remote sensing. With respect to remote sensing, the objective will be to extract geologic fracture/lineament patterns in the area of question through use of the LANDSAT satellite and high altitude aircraft imagery available from the United States Geological Survey (USGS) Eros Data Center. Similarly, recent low altitude and radar imagery (SLAR), will be collected and analyzed.

A comprehensive evaluation of stimulation alternatives in the Lawrence and Scioto County area would be of immediate benefit to the State of Ohio and the producers of the Appalachian area in providing relief to Ohio's natural gas shortage. Equally important, however, is the base case data available from the currently producing wells in that area. Only six (6) shale wells were drilled in Ohio in 1975. A successful stimulation program would substantially increase the number of shale wells drilled and produced.

In this program, we will be comparing stiff foam hydraulic stimulations with cryogenic stimulations. The questions we shall attempt to answer are:

1. Are the stimulation treatments technically and economically feasible?

2. What basic data relative to the shale is necessary before the techniques will be commercially viable?

3. Can we identify the zones where the treatment should be applied?

4. What are the basic formation characteristics of this area which have made it a good producer?

Although this area has historically been a good producer, very little factual shale data exists. We will establish through cooperation with the Ohio Geological Survey, a comprehensive set of shale data. Although we know this area to be a prolific gas producing area, there is no data to relate gas producing potential with basic shale characteristics.

In researching new techniques, we should first concentrate on the historically proven areas and then expand into the unknown areas. Our proposed program takes such an approach and is, therefore, aimed at providing maximum probability of success.

Foam, used as a fracturing fluid is a mixture of fluid, gas, a foaming surfactant and the propping agent. The liquid phase can be fresh water, diluted and concentrated acids, lease crude, etc. The surfactant is chosen to combine with this liquid and form foam when mixed with the gas. Currently, nitrogen is the gas used in foam fracturing due to its availability and other desirable qualities that make it acceptable to the oil field; however, many other gases could be used in FOAM-FRAC$_{TM}$.

Foam made with only these materials possess superior fluid-loss control, excellent proppant carrying capacity, and high viscosity. Chemical additives are not required to enhance either the viscosity or the fluid leak-off characteristics of the foam.

Application of foam fracturing has had impressive, but limited, success.

Minerals Management attributes the high deliverability increases in wells after stimulation with foam to the following:

1. The low natural fluid loss of foam limits invasion of the fracturing fluid to approximately one-half inch. Once production is initiated, the small amount of fluid is quickly returned to the fracture, and thus out of the well.

2. Absence of solid or chemical fluid-loss additives to control fluid leak-off during treatment leaves both the formation face and the proppant bed clean and thus maximum proppant-bed transmissivity can be utilized.

3. The liquids in the foam consititute only 10% to 30% of the total foam volume. In field applications of the technique, approximately 90% of the liquids have been returned indicating that the formation does not become saturated with fluid.

4. Clean-up time to date has been less than 12 hours on an average 20,000 gallon job. Well testing has usually commenced on the second or third day after fracturing. The short time the fluid is on the formation limits the amount of chemical reaction with the formation and clay absorption of the water.

Cryogenic treatments in the shale have heretofore been limited. At least three such treatments, two by Columbia Gas and one by Kentucky West Virginia Gas have been carried out. The results of the cryogenic treatments appear to be very positive. However, substantial additional work remains to be done to evaluate cryogenic treatment results and provide a quantitative basis of comparison.

WORK STATEMENT

Nine wells are proposed to be drilled in the general area of Lawrence and Scioto Counties in Ohio. Pipelines are available near the project acreage.

Geological evaluation of the area in Lawrence and Scioto Counties including remote sensing will be used to determine specific well locations. Every effort will be made to provide the stiff foam and cryogenic treatments with as similar conditions for test as possible, thus minimizing any bias that could occur through stimulating preferred wells with one type over the other. In the first six wells the stimulation designs will attempt to maintain the fracture radius per unit pay section constant for all treatments.

Three of the initial six wells in the program will be stimulated with foam, the second three will be cryogenic treatments. Wells seven through nine will await the results of the first six wells.

The specific stimulation designs must await downhole information. However, as a minimum the treatments are expected to be at least comparable in volume to the hydraulic stimulation presently being used in Devonian Shale. At this time, it is estimated that 140,000 gallon foam fractures and 40,000 gallon cryogenic fractures will be used on the first six wells.

The remaining three wells could be stimulated with larger treatments than wells one through six depending upon initial results.

DRILLING PROGRAM

Upon selection of the first three well sites, an 11" hole would be drilled to 1400 feet using air as the circulating medium to the bottom of the Berea Formation. The 8-5/8" casing would be set and cemented to surface. Coring would then commence using foam as the fluid system. The first well would be cored throughout the entire interval and selective coring of approximately 150 feet is projected for each of the two wells that follow. Samples would be obtained from 1400 feet to total depth at 10 foot intervals on those wells not cored.

Upon completion of logging and preliminary reservoir testing, 5-1/2" casing would be set at total depth and cemented. A 3000 psi working pressure wellhead would be installed and the rig moved to the next location.

There would be a gas detector unit on the well from the time the 8-5/8" casing is drilled out until total depth is attained. Information about total combustible gas and methane, liquid hydrocarbons and oil florescence in drill cuttings and lithology would be provided.

LOGGING PROGRAM

The following logging operations will be carried out on each well:

7-7/8 inch empty hole:

Temperature (1400 Feet to TD)
Sibilation (Optional)

7-7/8 inch fluid-filled hole:

Compensated Formation Density (1400 feet to TD)
Compensated Neutron Log (1400 feet to TD)
Gamma Ray (Surface to TD)
Borehole Compensated Sonic (1400 feet to TD)
Dual Laterlog (1400 feet to TD)

5-1/2 inch casing:

Cement Bond (1400 feet to TD)
Perforating Depth Control-Gamma Ray (1400 feet to TD)

Post Stimulation

Temperature
Spinner Survey
Gamma Ray - Beads

FRACTURE DESIGN

The fracture would consist of one projected fracture treatment in the selected shale interval. The maximum fracture interval has been chosen to be 150 feet. The actual interval to be treated would be determined upon completion of the well logging, coring and reservoir analysis.

CORING PROCEDURE AND ANALYSIS

The entire shale interval of the first well would be cored with foam after drilling to the top of the Shale section as determined by drill cuttings analysis. It is estimated that 150 feet will be cored in each of the next two wells. All core will be oriented. A 7-27/32 inch diamond core cutter with a 6-1/4 inch external diameter barrel would be used to cut a 4 inch diameter core.

Immediately after each barrel of core is surfaced, it would be removed from the barrel, packaged and shipped to the U.S. ERDA in Morgantown, West Virginia for core orientation.

The core would then be shipped to Core Laboratories, Inc. in Mt. Pleasant, Michigan for the following analysis: (1) Gamma Surface Log (2) Color Photo (3) Full Diameter Analysis, including porosity, grain density, fluid saturations, vertical permeability, oriented horizontal permeability in 45° quadrants (4) Gas Volume Test on Native State Core (5) Hydrocarbon Analysis (6) Core Slab (7) Fracture Analysis, and (8) Full Diameter Accoustic Velocity Test at 5 Overburden Pressures.

Core samples will also be sent to Cardinal Chemicals for Core Flow Tests and Foam Evaluation. Representative samples of the core will be sent to Halliburton and Dowell for chemical analysis, fluid compatability and basic fracture treatment design.

The Ohio Geological Survey plans a comprehensive evaluation of the Ohio Shale. To the extent possible, our program will compliment the OGS project and we shall extract the maximum information form the OGS project for application in our testing program. We will maintain constant liason with the OGS.

RESERVOIR TESTING

A consulting engineer will design the detailed well testing package for this program. It is anticipated that reservoir properties will be obtained from analysis of the logs and core where available. Drill stem tests will be run if significant shows of gas are encountered.

Open flows will be monitored throughout the coring and/or drilling phase of each well.

Each well will be tested after total depth is attained after the breakdown operation and after the stimulation in order to describe the capacity for production of the well.

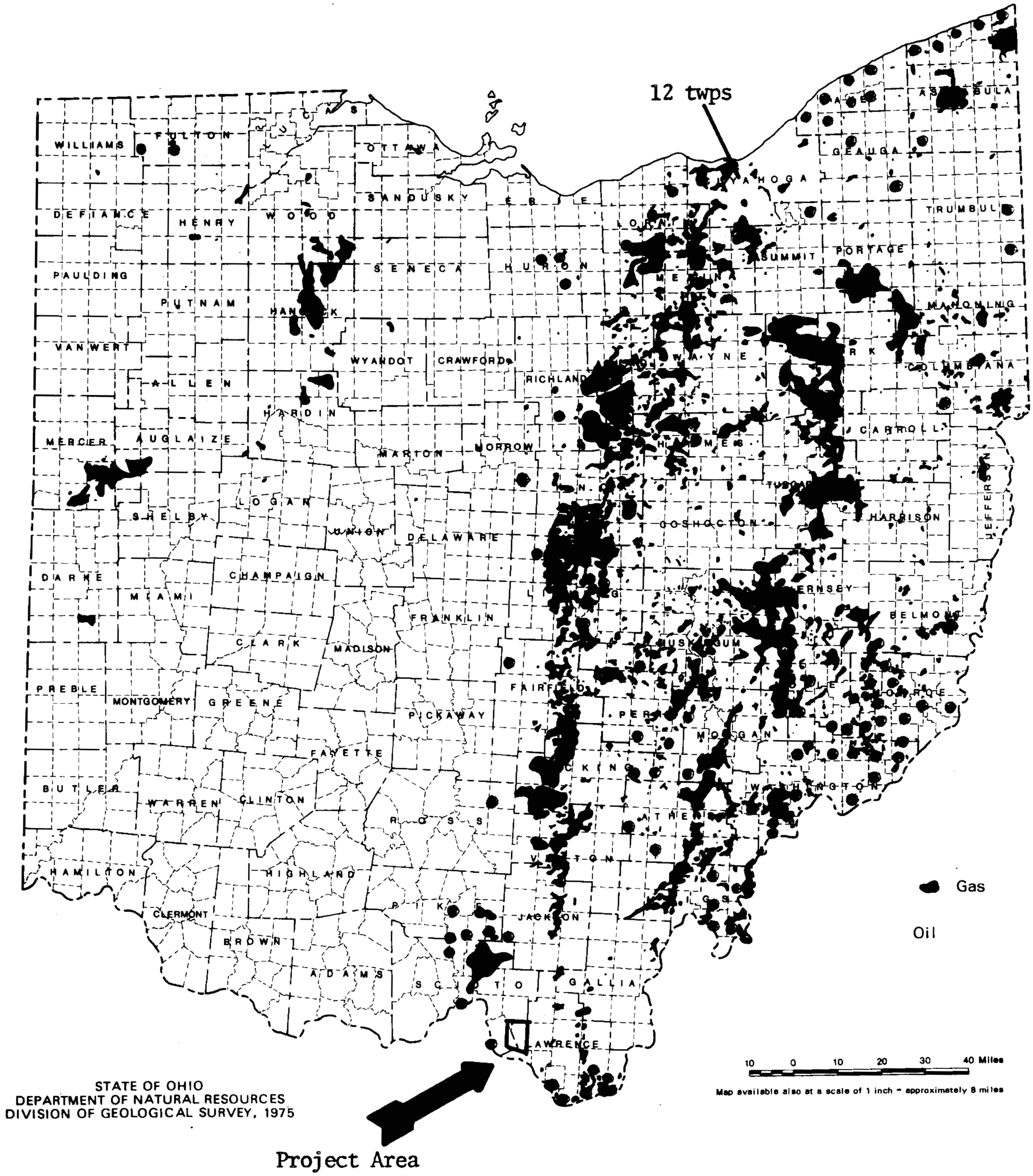
Modified isochronal four point deliverability tests and pressure draw down or build up tests will be conducted for sufficient amounts of time to obtain an optimum of information.

PROJECT PROGRESS

Phase I of our project, the geologic analysis of the area, has been completed. Dr. B. R. Henniger of Ashland College collected and analyzed Landsat and High Altitude Imagery, Side Looking Airborne Radar Imagery, and Infrared Imagery. By visual analysis, Dr. Henniger has identified and mapped the major natural fracture systems that occur on the surface in the project area. He then went into the area on foot to verify these fractures. Dr. Henniger could not cover the entire area that had been studied, but he did spend four days verifing the fracture systems that he had access to. Therefore, it is believed that the entire area studied has been accurately analyzed.

Dr. Henniger also measured surface fracture dips while in the area. Out of 255 fracture dip measurements, only one was in excess of 15° from vertical. Thus by drilling wells at intersections or zones of surface fracture systems, we should be able to encounter these same fracture systems at ±2000' in a shale well. If these systems are not encountered by the wellbore itself, due to the almost vertical dip, we should easily encounter them upon fracturing the well.

After compiling this data, Dr. Henniger recommended 9 primary and 12 alternate well locations on acreage within and surrounding the project area. Title surveys are now being done on these locations. Drilling of the first well should commence in August, 1977.



OIL AND GAS FIELDS OF OHIO

Figure 1 Townships from which productive (domestic and largely marginal commercial) shale wells have been recorded. Indicated by dot (●).

THE RELATIONSHIP OF THERMODYNAMIC AND KINETIC PARAMETERS TO WELL PRODUCTION IN DEVONIAN SHALE

by

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ABSTRACT

A mathematical model describing production of gas from wells in Devonian shales is introduced, and the extent of agreement with existing productivity data is discussed. Parameters needed for this model include the diffusion constant of gas through the rock and the sorption isotherms of gas within the rock. Methods and results of measurements of these important parameters made in our laboratories are described and discussed.

INTRODUCTION

This paper reports the results of efforts to model in the laboratory the process by which natural gas is released from tight formations (such as Devonian shales). The instrument for these studies is an apparatus in which a shale sample is initially equilibrated at some constant gas pressure; after equilibrium is reached, the pressure on the sample is suddenly changed and the rate and amounts of gas produced are monitored. The conceptual similarity of this laboratory process to the degassing of an underground reservoir is reflected in the similarity of gas loss curves produced in the laboratory with production rate curves of actual wells, except for differences in gas evolved and the time scale of evolution.

It is generally accepted that optimum production occurs in wells drilled into highly fractured areas. These fractures serve as conduits between the gas-producing rocks and the well bore. Initially, the gas in the fractures is in equilibrium with gas sorbed in the source rock; however, upon intersection of the fracture system by a well bore, the pressure in the fractures drops discontinuously, and the source rock evolves gas until equilibrium is re-established at the new pressure. The mathematical treatment of the rate of diffusion into the well bore as a function of time is thus similar to that of laboratory samples undergoing a discontinuous pressure decrease, the differences lying primarily in questions of geometry, magnitude of rock involved, and size of initial pressure drop.

This paper deals with three main topics. First, the ideas discussed above are presented in quantitative form. It is shown that the diffusion constant of methane in shale and the extent and frequency of fractures collectively are the

Prepared for ERDA under Contract No. E(40-1)-5197.

determining parameters of well production. Of these three factors, the first two are particularly amenable to laboratory measurement; the second and third sections of this paper deal with efforts in this regard.

THEORETICAL

The purpose of this section is, first, the mathematical description of the underground processes that lead to gas production from tight formations and, second, the comparison of that description to the mathematical description of the degassing of rock in laboratory configurations.

Production from wells in relatively impermeable formations depends upon drilling into highly fractured areas and/or creating them artificially after the well has been drilled. These fractures serve primarily as conduits from the gas-bearing source rock to the well bore. The amount of gas diffusing out of a shale into a fracture (held at a low pressure) is given by (1,2)

$$1)\quad M_T = 2(C_2 - C_0)A\left(\frac{Dt}{\pi}\right)^{\frac{1}{2}}$$

$$\frac{dM_T}{dt} = (C_2 - C_0)A\left(\frac{D}{\pi t}\right)^{\frac{1}{2}}$$

where

- A is the area of rock degassing.
- C_2 is the initial concentration of gas in the rock.
- C_0 is the concentration of gas in the rock as $t \rightarrow \infty$.
- D is the diffusion constant.
- t is the time.

Over a ten year period, for reasonable values of parameters for Devonian shale ($D = 5 \times 10^{-7}$ cm^2/sec, $C_2 - C_0 = 3$ cm^3 gas/cm^3 rock), 40 cm^3 gas (STP) would be produced for each square centimeter of fissure wall area. This amount of gas is clearly much larger than the amount of gas contained between the walls of the average fracture, thus lending support to the concept that the rock is the source of the gas and that fractures serve as conduits. It is interesting to note that the production curve predicted by equation 2) is high production over a relatively short period followed by a long tail. In fact, 32% of the total gas produced over a 20-year period is produced in the first two years, in agreement with some qualitative reports of well production from some producing wells by Roth (3) and Torrey (4). Whereas initial well production is large, the inverse square root dependence on time implies that after the initial large production reduced production will occur unabated for many years, again in agreement with many reports of the longevity of gas shale wells.

The upper curve of Figure I shows some actual production data points (5) and an inverse square root fit versus time as the solid line. Although the fit for that well is good, it is clear that not all wells display such a simple relationship. In particular, as the lower three curves show, the initial high production rate may, to a variety of degrees, be missing.

Flattened production curves result from a mathematical viewpoint if it is assumed that an additional constriction exists at the surface of a fracture or along the fracture to the well bore that impedes the diffusive process of gas from the bulk rock. Such surface modification would be expected to occur at slickensides wherein an impermeable-looking, glaze-like finish is formed on the rock. Alternatively, mineralization may occur within the fracture, plugging the microporous surface structure of the shale. Constrictive effects along the fracture would be expected when a narrow fracture is "overloaded" by a large gas flow. All of these effects, which might be expected to be common occurrences in actual situations, should result in flattened (and decreased!) well productivity curves.

The lower curves in Figure I are fits taking in account constrictive effects of varying degrees of importance. The equation of fit is

$$2)\quad \frac{dM_T}{dt} = \frac{D(C_2 - C_0)}{g} \exp(z^2) \operatorname{erfc}(z)$$

$$z = \frac{D^{\frac{1}{2}}}{g} t^{\frac{1}{2}}$$

Equation 2) has been discussed in detail elsewhere (6).

Briefly, g is a constrictive parameter corresponding to some kind of impermeable coating on the fracture surface. The more impermeable the coating, the larger g is; conversely, for decreasing constrictive effects g approaches zero and equation 2) approaches equation 1). Figure II shows this effect explicitly.

The middle curve is simply the lower curve of Figure I with g = 6.318. The upper and lower curves are with identical parameters (same fracture area, same bulk rock diffusion constant and gas concentration) except that g = 0 and 30 cm for the upper and lower curves respectively. It is clear from Figure II that the effect of constrictions is to decrease markedly total production and flatten it in respect to time.

In contrast to the flattening observed in wells, most laboratory samples will give somewhat steeper curves than predicted by a simple $t^{-\frac{1}{2}}$ law; specifically experimental points will follow equation 1) closely at low t but fall below the theoretical curve at large times. This feature may not be limited to laboratory samples; in fact the points of the most productive curve of Figure I form a slightly steeper curve than the fit shown. The explanation for this phenomenon lies in the geometry of the fractures in the case of a well and the particle shapes in the case of laboratory samples; in fact the applicability of equations 1) and 2) is limited to the case where the depletion zones (6) associated with each fracture do not interfere. As a surface degases, the rock behind the surface becomes depleted to an ever-increasing extent, this zone of depletion initially extending only a short way into the rock but the extension increasing with time. Specifically

$$3)\quad d \cong \sqrt{Dt}$$

where d is the depletion zone mentioned above. When d is much smaller than the dimensions associated with rock fragments or distances between fractures, equations 1) and 2) can be expected to be obeyed. However, as time increases, d increases until it eventually becomes of the order of the fracture or particle dimensions. At this point the depletion zone from one fracture starts to move into areas already depleted by another fracture, and gas production tapers off below that predicted by the $t^{-\frac{1}{2}}$ law.

Exact functions exist and have been utilized for several laboratory degassing situations, as is discussed elsewhere (6,7,8). Although it would appear from Figure I that geometric effects are not important in wells, they may nevertheless sometimes be detectable. As discussed elsewhere (6) the anomalous steepness of the top curve of Figure I corresponds to a mean distance between fractures of 65 cm. Anomalous steepness and large productivity may thus be linked together as both are indications of production from highly fractured zones.

DIFFUSION CONSTANTS

Diffusion constants and permeability constants are closely related.

$$D = P/K$$

where D is the diffusion constant, P is the permeability constant, and K is the solubility of gas in the rock,

$$C = KP$$

where C is the equilibrium concentration of gas in the rock, and P is the applied pressure. Diffusion (and/or permeability constants) can be measured by determining the rate that gas passes through a cut slab of sample or alternatively it can be deduced from the rate a sample of rock degases. The latter method has the advantages that it is quicker, often taking only a few minutes to get a measurement, and is more closely related to the actual underground degassing process.

In our procedure, we first equilibrate the sample at a constant pressure. For sieved samples, this typically takes less than an hour and is done on the measuring apparatus. For slabs equilibrated to 1 atm methane, the equilibration takes several days and is done before placing the sample on the measuring apparatus. As shown in Figure III, the cell is separated from a carefully calibrated volume (9) by a valve. After measuring the initial equilibrium pressure, the valve is closed, and the volume associated with the buret, etc., changed to a new pressure (typically evacuated). An automatic data-taking routine associated with a NOVA 1220 laboratory computer is started which takes pressure readings from the Datametrics Barocel. Then the valve between the cell and the calibrated volume is opened. The pressure changes resulting are monitored at a data collection rate of 25,000 readings/second for a period of several minutes for particles and about one-half hour for slabs. The pressure changes which occur after the initial pressure drop are due to the degassing of the sample. The amount of gas given off follows (initially) a $t^{\frac{1}{2}}$ law whose slope is interpretable in terms of the diffusion constant as discussed earlier for wells. The detailed procedures for slabs and particles are somewhat different, and the details are discussed elsewhere (7,8).

Table I shows results obtained at a variety of depths from Well #20403 drilled by Columbia Gas Corporation in conjunction with the Eastern Gas Shales Project. The average methane diffusion constant is 6.56 x 10^{-7} cm^2/sec with a standard deviation of ±4.18 x 10^{-7} cm^2/sec. This range represents the approximate range of diffusion constants within the Devonian shale sequence (at the Lincoln County well, etc.). There is a dependence of the diffusion constant upon the temperature and/or type of gas used. For example, our 77°K N_2 diffusion constants average 2.3 times the ice temperature methane constants although individual comparisons can deviate from this figure. There is a dependence of diffusion constant upon particle size. For data reported elsewhere (8), N_2 diffusion constants at 77° K for 500-700 μ averaged 4.5 times the value for 175-350 μ mesh size. As a general rule, work on slabs supports this contention. A sample at 3886' 2-4" gave a diffusion constant of 2.5 x 10^{-7} cm^2/sec for 175-350 μ mesh size, 15.4 x 10^{-7} cm^2/sec for 500-700 μ mesh size, and 116.1 x 10^{-7} cm^2/sec for a slab of shale at 3886' of dimensions 27.88 cm^2 by .72 cm thick. This size effect can be accounted for by two possible mechanisms. It may be that highly impermeable components of shale fracture more easily into material of smaller mesh size. The second possibility is that the grinding process decreases the number of microfractures or other zones of weakness associated with high diffusivity by cleaving along, hence eliminating them. Our data supports the second hypothesis; the first hypothesis would suggest that slab diffusion would be intermediate between large and small particles, an effect which has not been observed to date. Further, there is no obvious difference between the large particles and the small ones as observed under an optical microscope.

The effect of manner of sample preparation may have some effect upon results. Table II shows an increase of diffusion in samples prepared by percussion mortar. Optical examination suggests that the samples prepared by ball mill are abraded more than samples prepared by percussion mortar. If this is the case, diffusion of samples prepared by percussion mortar ought to be more representative of "bulk shale" than those prepared by ball mill. Table III shows a very interesting effect observed with slabs. The first and third samples show a methane diffusion for slabs that is some 4.5 times larger than for particles from the same shale. However, the second sample of Table II shows a slab diffusion that is only 15% of the particle diffusion. This surprising result may be understood in terms of surface preparation. Before making the measurements, the slab surfaces are ground down by peeling the surface down with a chisel. Whereas usually this results in a dull-looking surface, for the anomalous result in question a shiny, impermeable-looking, slickenside-like surface resulted. We believe that the effect of rubbing with a chisel on this sample was to produce a thin impermeable layer that lowered the rate of outgassing by about a factor of 40 over that produced from surfaces split by a percussion mortar. Work on this tantalizing but speculative area is continuing.

ISOTHERMS

The value of the determination of isotherms is at least twofold. First, it allows the estimation of concentration of gas in the rock surrounding a well given only the initial wellhead pressure. In this sense an isotherm plays the same role as porosity in standard oil technology. However, the concept of an isotherm is more general because it is a measure of all gas in the rock, that in open pores, that adsorbed on the surface of minute clay particles, and that dissolved in some kerogen or other material entrained in the rock. Some practical implications of this have been discussed elsewhere (10). The second value of an isotherm is that it permits, at least to some degree, the determination of which of these mechanisms of entrainment are operative--open porosity, adsorption, or solution. More discussion on this point has been made elsewhere (11

Figure IV shows some typical isotherms, showing the degree of entrainment of ethane, methane, argon and helium, all on the same sample. It should be noted that these isotherms are all straight lines within this region and hence can be associated with a "porosity." However, the porosity calculated from each gas is different, corresponding to 40%, 13%, 7%, and 3%, for C_2H_6, CH_4, An, and He respectively. As this makes no physical sense for open pores, one can only conclude that what is measured is an "effective porosity" which includes substantial amounts of adsorption and/or solution. A corollary to this is that the most appropriate measure of porosity to be associated with natural gas production is "methane porosity" obtained by direct measurement of amount of methane sorbed as a function of pressure.

In addition to the data reported in Reference 14, we have measured room temperature isotherms for the 17 samples in Table I. If it is assumed that helium sorption is due only to penetration of the open pores, the straight line He plots can be reinterpreted in terms of a helium density (wt. of sample/ volume of unpenetrated samples). Helium densities average $\sim$.04 g/ml higher than bulk densities corresponding to an average porosity of 1%. The vol. gas/ vol. rock/torr for methane given in Table I is that in excess of that associated with the pore volume (as determined by the He isotherms). It is useful to note that the methane isotherms slopes are grouped around 3.27×10^{-4} vol. methane/vol. rock/torr (±42%) even though an effort was made to include a variety of lithologies in the 17 samples included in Table I.

In addition to room temperature isotherms, we have also determined isotherms of N_2 determined at liquid nitrogen temperatures. The value of this measurement is several-fold. First, if one assumes that the kerogen freezes to an impermeable solid at liquid nitrogen temperatures, then any sorption that takes place must be adsorption on the various surface areas associated with the small particles of clay minerals. Under these conditions a standard BET analysis is possible (13). We find good fits to the BET isotherm which lends support to the adsorption model (at least at low temperatures) and results in a determination of the surface area available for adsorption. For shale samples that we have measured, this varies from a few tenths to several meters squared per gram (14). This is a small fraction of the surface area associated with clay minerals (illite is 92 m^2/g (15)), but nevertheless sufficient to show that sufficient adsorptive capacity exists within Devonian shales to account for the amounts of methane observed.

In Table I, we have shown the nitrogen BET surface areas in terms of the volume of gas that would be required to cover the available surface area with a monolayer. This should represent the maximum amount of methane that can be adsorbed onto surface areas within the rock, as significant multilayer adsorption of methane would not be expected at temperatures present in the ordinary well.

A major point of interest concerns the degree of correlation between the isotherm parameters of Table I and the amount of gas found in the rock. We received the 17 samples reported in Table I in sealed cans along with about

213 other samples taken at 10-foot intervals down the well. After a wait of 142-156 days, the atmosphere in the cans were analyzed for O_2, N_2, CH_4, C_2H_6, C_3H_8, CO_2, H_2, and H_2S by gas chromatography (17,18). The results for the 17 samples of Table I is summarized in Table IV. Several features are worthy of note. First, there is no close correlation between the parameters of Table I and gas content. In particular, gas content ranges over several orders of magnitude from sample to sample wherein the parameters of Table I are relatively constant. This may be expected because the isotherms of Table I essentially measure the capacity for gas content as a function of pressure. Since these remain relatively constant from strata to strata and gas content varies, it is concluded that the original gas pressure in the rock must vary considerably in various parts of the well. A consequence that follows from this is that even over geologic time the thermodynamic equilibrium of methane does not seem to be reached even in strata as close together as about 50 feet.

Several other features of Table IV include the observation that often the desorption of hydrocarbons is closely correlated with approximately equimolar adsorption of nitrogen and oxygen originally present in the can at sealing time so that the total pressure remains constant. Oxygen nitrogen ratios vary from can to can and are generally too high to account for the loss of air by can leakage; this suggests some kind of molecule-for-molecule displacement mechanism. Methane, ethane, and propane usually appear in decreasing amounts in concordance with the observations of other investigators (19,20). Finally, gas production seems relatively well correlated with the appearance of black shale as noted by the well site core description, although this is certainly not a hard and fast rule.

CONCLUSIONS

A major conclusion would seem to be that the isotherm and diffusion parameters are not sensitive functions of depth or lithologic type of Devonian shale at least in the vicinity of the #20403 well. If this holds for other locations as well, this means that averaged parameters can safely be used in well modeling studies of the type discussed in the introduction -- a great simplification.

Apparently even relatively close layers of rock within the Devonian shale sequence are not in quilibrium with each other in respect to the chemical potential of hydrocarbon gases. More work needs to be done in this area; in particular we are interested in measuring the diffusion constants of slabs cut parallel to the bedding planes. A practical consequence of non-equilibrium is that the well bore becomes a mechanism by which equilibrium can be obtained. Gas from an outgassing region can be trapped by an adsorbing region; thus it is lost to production. The possible magnitude of this effect is under study in our laboratories.

Finally it seems possible to reach some speculative conclusions pinpointing the slickenside nature of many natural fractures as a source of slow well production. Fits to at least some available production data point to the presence of slickensides or some similar localized constriction in the passage of gas from the source rock to the well bore. This correlates with comments of various personnel involved with cataloging natural fractures (21) that most natural fractures are slickensided or mineralized. At the moment, pinpointing slickenside formation as a major culprit in the observed constrictive effects is supported by a single laboratory measurement. This is not to imply that slickensided fractures are detrimental to production (total production is the sum of the production from each fracture), but rather that the removal of constriction from existing fractures will itself raise production significantly. Work on the role of slickensides in well constriction and their possible removal is continuing.

ACKNOWLEDGMENT

The authors wish to thank the Energy Research and Development Administration under whose auspices this work was accomplished under Contract No. E(40-1)-5197. In addition, the authors wish to thank D. Steven Hench, Eugene Boden, Martha Linton, Jay Nelson, Eric Jensen, Sharon Steckbeck, and Linda Hoeflich, who collected much of the data.

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FIGURE CAPTIONS

FIGURE I

Flow rate (million cubic ft/da.) is plotted against time (years). Data is from Ref. 5. The lines are fits as described in the text. Values of the parameters are as follows from upper to lower curves.

Size (meters^2) x 10^{11}	g (cm)
1.21	0
.845	4.79
.506	6.02
.254	6.32

FIGURE II

The effect of localized constrictions on well production. The lower curve shows production from a well with a high degree of localized construction. In the upper curves these constrictions are progressively removed. Note that production increases and shifts to lower times.

FIGURE III

Our laboratory apparatus. The slabbed or ground sample is placed within the cell. Initially there is a known pressure differential across V_1. After V_1 is opened, the Datametrics Barocel monitors pressure changes as a function of time. The calibrated buret permits quantitative interpretation of the pressure readings in terms of rates and amounts of gas production.

FIGURE IV

Moles of various gases sorbed on a 5.6 gram sample as a function of pressure at 30°C. The slopes correlate well with the molecular polarizabilities suggesting a simple adsorption mechanism for entrainment of gas in the rock.

TABLE I. DIFFUSION AND ISOTHERM PARAMETERS, Well #20403, Lincoln County, West Virginia

Sample I.D.	Corrected Depth	Bulk Density (g/cm^3)	Isotherms: He Density (g/cm^3)	Isotherms: Initial Slope 0°C (Vol Gas/Vol Rock/Torr x 10^{-4}) CH_4	Isotherms: Surface Area (Vol Gas/Vol Rock) N_2 @ 77°K	Diffusion Constants (cm^2/sec x 10^{-7}): CH_4 @ 0°C	Diffusion Constants (cm^2/sec x 10^{-7}): N_2 @ 77°K	Well Site Core Description
2736' 2-4"	2736' 2-4"	2.75	2.53	4.70	6.20	3.98	12.8	Med. gray-green laminated silty shale
2806' 2-4"	2808' 2-4"	2.61	2.57	6.12	3.15	4.95	15.6	Med. dark gray silty shale
3096' 2-4"	3101' 2-4"	2.51	2.68	2.84	1.63	14.1	7.75	Med. to dark gray shale
3136' 2-4"	3141' 2-4"	2.70	2.70	3.28	5.90	3.35	11.5	Dark gray shale
3156' 2-4"	3161' 2-4"	2.61	2.70	3.52	4.94	9.87	12.9	Dark to med. gray shale
3281' 2-4"	3291' 2-4"	2.85	2.91	1.72	4.45	14.4	14.1	Med. to dark gray shale
3396' 2-4"	3407' 2-4"	2.68	--	3.32	--	5.06	8.19	Med. gray shale with black shale bands
3416' 2-4"	3428' 2-4"	2.65	2.56	3.35	.730	2.90	12.7	Very dark gray & black banded shale
3426' 2-4"	3438' 2-4"	2.37	2.56	3.82	1.30	3.90	8.72	Black shale
3446' 2-4"	3458' 2-4"	2.46	2.667	3.46	.690	3.25	22.0	Black shale
3456' 2-4"	3468' 2-4"	2.58	2.59	3.01	1.53	11.5	10.0	Med. gray shale
3496' 2-4"	3509' 2-4"	2.40	2.57	2.18	.71	6.91	11.5	Black shale
3716' 2-4"	3733' 2-4"	2.67	2.73	1.81	5.51	5.36	20.1	Blue gray & black laminated shale
3836' 2-4"	3855' 2-4"	2.60	2.73	1.66	4.90	3.61	28.9	Blue gray shale
3896' 2-4"	3914' 2-4"	2.68	2.58	2.02	4.69	5.05	30.0	Med. gray & dark gray laminated shale
4006' 2-4"	4026' 2-4"	2.67	2.62	2.53	5.21	10.7	18.2	Laminated dark gray and gray green shale
4026' 0-2"	4046' 0-2"	2.41	2.47	6.30	.559	1.35	12.6	Black shale

TABLE II. COMPARISON OF TYPE OF GRINDING

	Ball Mill	Percussion Mortar
Sample I.D.	3446' 2-4"	3446' 2-4"
Corrected Depth	3458' 2-4"	3458' 2-4"
Bulk Density (g/cm^3)	2.46	2.46
Isotherms--		
He Density (g/cm^3)	2.47	2.67
Initial Slope $0^\circ C$		
(Vol Gas/Vol Rock/Torr x 10^{-4}) CH_4	3.31	3.46
Surface Area (Vol gas/Vol Rock) N_2 @ $77^\circ K$	1.40	.690
Diffusion Constants ($cm^2/sec \times 10^{-7}$)--		
CH_4 @ $0^\circ C$	2.59	3.25
N_2 @ $77^\circ K$	6.91	22.0
Well Site Core Description	Black shale	Black shale

TABLE III. DIFFUSION OF CH_4 IN SLABS AT $0^\circ C$

Sample I.D.	Corrected Depth	Diffusion Constant ($cm^2/sec \times 10^{-7}$)	Well Site Core Description	Slab Surface Description
2736' 2-4"	2736' 2-4"	12.5	Med. gray-green laminated silty shale	Dull
3426' 2-4"	3438' 2-4"	.589	Black shale	Shiny
3836' 2-4"	3855' 2-4"	22.0	Blue gray shale	Dull

TABLE IV. OUTGASSING RESULTS, Volume of Gas Per Unit Volume of Rock

Sample I.D.	V_{CH_4}	$V_{C_2H_6}$	$V_{C_3H_8}$	V_{CO_2}	V_{O_2}	V_{N_2}
2736' 2-4"	.028	0	0	0	-.06	.08
2806' 2-4"	0	0	0	0	-.06	.07
3096' 2-4"	.127	.04	0	0	-.135	-.03
3136' 2-4"	.09	.03	0	0	-.09	.02
3156' 2-4"	.08	.04	0	0	-.1	0
3281' 2-4"	.06	.02	0	0	-.05	.05
3396' 2-4"	.200	.05	.02	0	-.15	-.11
3416' 2-4"	.740	.246	.154	.157	-.473	-.53
3426' 2-4"	.565	.215	.139	0	-.26	-.65
3446' 2-4"	.704	.242	.158	0	-.29	-.54
3456' 2-4"	.270	.078	.040	0	-.14	-.15
3496' 2-4"	.12	.047	.016	0	-.072	-.11
3716' 2-4"	.004	0	0	0	-.04	.02
3836' 2-4"	0	0	0	0	.005	-.005
3896' 2-4"	.265	.073	.02	0	-.12	-.001
4006' 2-4"	.37	.12	.025	0	-.24	-.01
4026' 2-4"	1.37	.523	.239	0	-.30	-.18

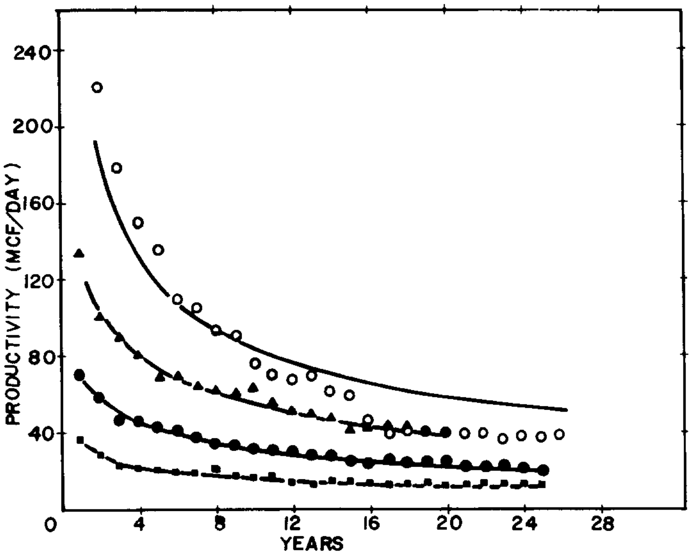

Figure 1

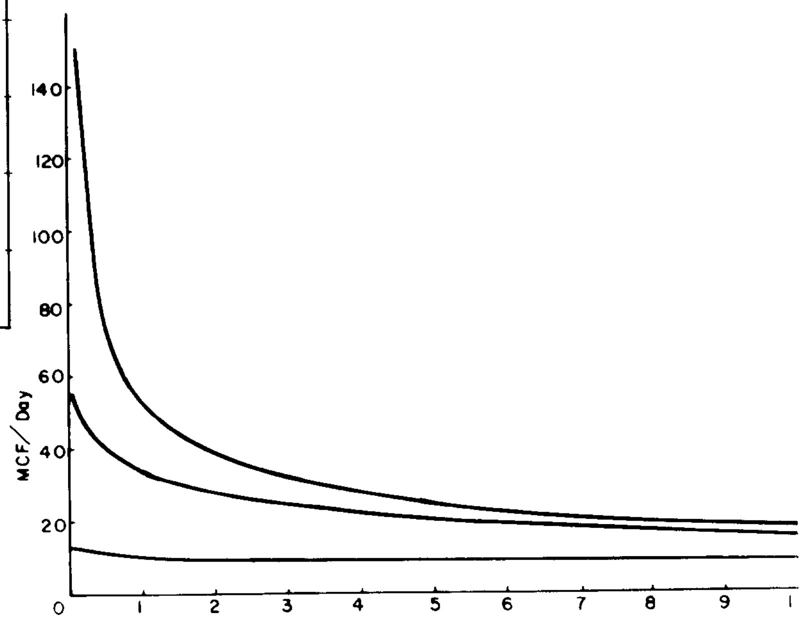

Figure 2

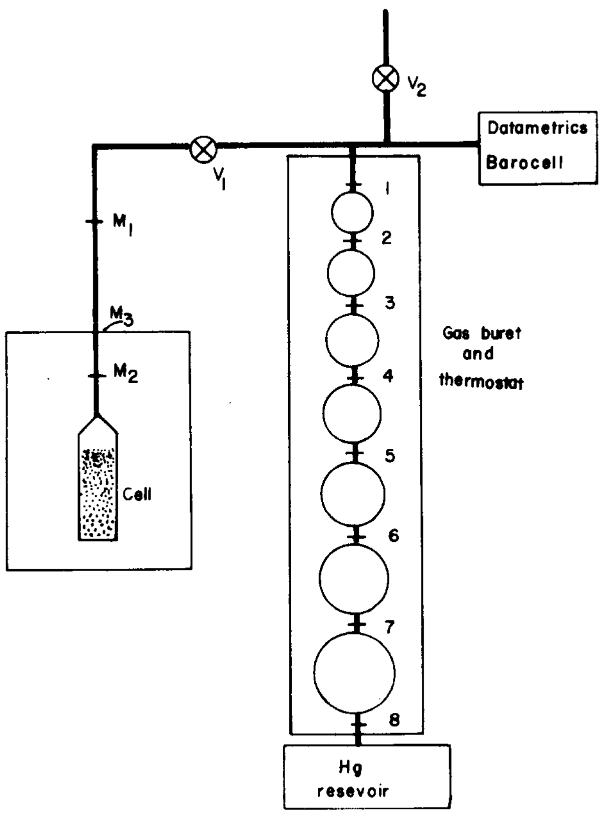

Figure 3

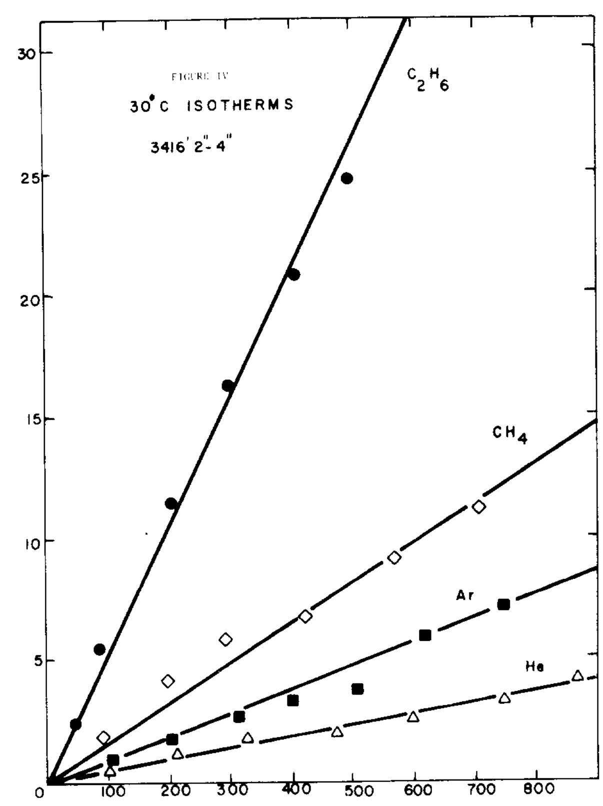

Figure 4

THE NEW ALBANY SHALE AND CORRELATIVE STRATA IN INDIANA

by

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ABSTRACT

The New Albany Shale has a maximum thickness of 337 feet in southwestern Indiana and thins northward and eastward to about 90 feet in the outcrop area. In the Michigan Basin, strata equivalent to the New Albany are 348 feet thick in Lagrange County. The base of the New Albany is 4,500 feet below sea level in southwestern Indiana, and the base of the Antrim Shale is 150 feet above sea level in northern Indiana (Lagrange County).

In the Illinois Basin the New Albany is divided into four members: the Hannibal, Grassy Creek, Sweetland Creek, and Blocher Shales. The lithologic equivalents of the New Albany in the Michigan Basin are the Sunbury, Ellsworth, and Antrim Shales.

The New Albany produced commercial gas from seven fields in Harrison County and one field in Martin County. Two small gas fields have been found in the New Albany in Daviess County.

OBJECTIVES

The first phase of the Eastern Gas Shale Project in Indiana has consisted of collecting drill hole data on the New Albany Shale and equivalent strata and studying the stratigraphy and structural framework of the units.

Through July 1, 1977, study has been concentrated on five principal aspects: (1) preparing a map showing location of New Albany datum points, (2) dividing the New Albany into four members in the Illinois Basin, (3) determining the structure on both the top and the base of the formation, (4) preparing a map showing the thickness of the New Albany and equivalent rocks, and (5) preparing maps showing gas shows in the New Albany and underlying Middle Devonian limestone.

INTRODUCTION

Carbonaceous shales of Devonian-Mississippian age are present in the Illinois Basin in southwestern Indiana and in the Michigan Basin in northeastern Indiana. The New Albany Shale in the Illinois Basin was once continuous with that of the Michigan Basin, but it has been removed by erosion along the northwestward-trending Cincinnati Arch (Lineback, 1970, p. 2).

Prepared for the Energy Research and Development Administration, under Contract No. EY-76-C-05-5204.

The New Albany paraconformably overlies the Middle Devonian limestone southwest of the Cincinnati Arch province. The New Albany is overlain by the Rockford Limestone in southwestern Indiana except where the Rockford is not present and the New Albany is directly overlain by the Mississippian New Providence Shale (Borden Group). In the Michigan Basin strata equivalent to the New Albany overlie the Middle Devonian limestone and are overlain by the Coldwater Shale (Mississippian).

In southwestern Indiana the New Albany Shale crops out on the flank of the Cincinnati Arch, where it ranges in total thickness from 90 to 130 feet. The rocks both dip and thicken southwestward into the Illinois Basin and attain a maximum thickness of 337 feet in extreme southwestern Indiana. In the southern part of the Michigan Basin strata equivalent to the New Albany are as much as 348 feet thick.

The two dominant lithologies of the New Albany are a brownish-black organic shale and a greenish-gray nonorganic shale. The brownish-black organic shale constitutes more than 80 percent of the New Albany in the southwestern part of the Illinois Basin (Lineback, 1970, p. 4). Elsewhere in Indiana the brownish-black organic shale constitutes only 20 to 40 percent of the New Albany Shale and equivalent strata (Lineback, 1970, fig. 2).

The counties referred to in this paper are shown in figure 1.

STRATIGRAPHY

Illinois Basin:

The name New Albany Shale was proposed by Borden (1874, p. 158) for the brownish-black shale exposed at New Albany, Floyd County, Indiana. On the basis of lithology, paleontology, and jointing, Campbell (1946, p. 835) subdivided the unit into several formations and members. On the basis of lithology, Lineback (1968, p. 1291) subdivided the New Albany into five members in the outcrop belt: Blocher, Selmier, Morgan Trail, Camp Run, and Clegg Creek (in ascending order). Becker (1974, p. 45), using lithologic samples and geophysical logs, recognized the lowermost outcrop member, the Blocher, in the subsurface in the Illinois Basin, but he did not differentiate other outcrop members in the subsurface. He (1974, p. 45, 46) also recognized and described the Hannibal Member as the uppermost member of the New Albany Shale in the subsurface of Indiana.

In the present study five north-south and six west-east stratigraphic cross sections were compiled by using geophysical logs of 109 selected wells in the Illinois Basin. Lithologic strip logs for the selected wells were examined when they were available. As a result of this study the subsurface New Albany has been subdivided into four members: Blocher, Sweetland Creek, Grassy Creek, and Hannibal (in ascending order).

Blocher Member - The name Blocher Formation was first used by Campbell (1946, p. 840) for the brownish-black organic-rich calcareous to dolomitic shale in the basal part of the New Albany. Lineback (1968, p. 1295) redefined the Blocher of Campbell by raising the upper boundary of the unit to the base of the greenish-gray shale of the Selmier Member. Collinson and others (1967, fig. 13), using geophysical data, mapped the thickness and distribution of this unit in the Illinois Basin. Lineback (1970, fig. 7), using lithologic characteristics, mapped the Blocher in southwestern Indiana slightly thicker than Collinson and others. In this report recognition and thickness of the unit are based primarily on geophysical log evidence.

On electric logs the Blocher is recognized as a high-resistivity unit at the base of the New Albany overlying Middle Devonian limestone in the Illinois Basin (fig. 2A). The Blocher is 48 feet thick in the southwestern part of the basin and thins to the north and east. North of central Vigo County the Blocher is not recognized on electric logs.

Sweetland Creek Member - The name Sweetland Creek was first used by Udden (1899, p. 65-78) for strata exposed along Sweetland Creek, Muscatine County, Iowa. The Sweetland Creek Shale as redefined by Collinson and others (1967, p. 960) is restricted to the greenish-gray shales underlying the Grassy Creek (a black organic shale) at the type section. Meents and Swann (1965, fig. 4) traced the Sweetland Creek as an "unnamed shale" from Illinois into southwestern Indiana.

In the subsurface of Indiana the name Sweetland Creek Member of the New Albany Shale is being applied to the slightly calcareous to dolomitic greenish-gray to very dark-gray shale underlying the black shales of the Grassy Creek. The Sweetland Creek overlies the Blocher in the deeper part of the basin; however, where the Blocher is not present, north of central Vigo County, the Sweetland Creek rests on Middle Devonian limestone. The shales of the Sweetland Creek are generally lighter in color and have a lower resistivity on an electric log than the Blocher or the Grassy Creek (fig. 2A).

The Sweetland Creek is 49 feet thick in Posey County and thins eastward to 13 feet in Washington County. The unit thins northward to northern Vigo County, and north of that point it thickens slightly at the expense of the overlying Grassy Creek.

Grassy Creek Member - The Grassy Creek Shale was named by Keyes (1898, p. 59-63) for exposures along Grassy Creek in Pike County, Missouri. Meents and Swann (1965, fig. 4) and Collinson and others (1967, fig. 7) recognized the Grassy Creek in the subsurface of Illinois and traced this unit into southwestern Indiana.

In the present study the name Grassy Creek Member of the New Albany Shale is applied to the brownish-black organic-rich pyritic noncalcareous shale that overlies the Sweetland Creek and underlies the greenish-gray shales of the Hannibal. In the subsurface the high resistivity of the unit on electric logs differentiates it from the units below and above (fig. 2A). The Grassy Creek is 118 feet thick in Posey County and becomes thinner and less organic to the north and east.

Hannibal Member - The Hannibal Shale was named by Keyes (1892, p. 289) for 75 feet of sandy shale exposed at Hannibal, Missouri. The Hannibal is as much as 100 feet thick in western Illinois and thins eastward in the Illinois Basin (Willman and others, 1975, p. 130). Meents and Swann (1965, fig. 4) and Collinson and others (1967, p. 947) traced a combined Hannibal-Saverton unit into southwestern Indiana. Becker (1974, p. 48) proposed that in the subsurface of Indiana the name Hannibal Member of the New Albany Shale be applied to the greenish-gray shale that lies between the base of the Rockford Limestone and the top of the black shales of the New Albany.

The Hannibal is greenish-gray noncalcareous low-organic shale characterized by low electrical resistivity on a geophysical log (fig. 2A). This unit can be differentiated from the greenish-gray shales of the New Providence only when overlain by the Rockford Limestone. It is 48 feet thick in Posey County and thins eastward in the basin.

Michigan Basin:

In the southern part of the Michigan Basin three stratigraphic cross sections were compiled by using geophysical logs of 29 selected wells. Three units equivalent to the New Albany are recognized in northern Indiana: the Antrim, Ellsworth, and Sunbury Shales (from oldest to youngest). These units are more than 340 feet thick in Lagrange County (fig. 3) and thin to the east and west. In the western part of the Michigan Basin the New Albany equivalents are overlain by thick glacial drift, and to the east in Lagrange, Steuben, Noble, and DeKalb Counties they are overlain by the Coldwater Shale (Mississippian). In general, the strata have a lower percentage of organic material than the New Albany does in the Illinois Basin (Lineback, 1970, fig. 2).

Antrim Shale - The name Antrim Shale was proposed by Lane (1901, p. 9) for an exposure of shale in Antrim County, Michigan. The Antrim in the southern part of the Michigan Basin is predominantly black organic-rich shale with greenish-gray calcareous shale in the lower part of the unit from LaPorte County eastward. The natural gamma radiation of the unit, except for the lower part, is high (fig. 2B). The Antrim ranges from about 70 to 220 feet in thickness and thickens eastward as the greenish-gray shale of the Ellsworth grades into the black organic shale of the Antrim.

Ellsworth Shale - The name Ellsworth Shale was formally proposed by Newcombe (1933, p. 49-51) for greenish-gray shale exposed in a quarry near Ellsworth, Antrim County, Michigan. The lower part of the Ellsworth Shale consists of interbedded greenish-gray nonorganic shale and black organic shale that exhibits moderate to high natural gamma radiation. The upper part of the Ellsworth is greenish-gray nonorganic shale characterized on a gamma ray log by low gamma radiation (fig. 2B). Both the upper and lower parts of the Ellsworth extend into the northern part of the Illinois Basin (Lineback, 1970, p. 32). The upper part may correlate with the Hannibal Member of the New Albany Shale.

Sunbury Shale - The Sunbury Shale was originally described as the Sunbury Black Slate by Hicks (1878, p. 216, 220) for shale exposed in Delaware County, Ohio. The Sunbury in northern Indiana is black organic shale about 10 feet thick. This unit has high gamma radiation and is recognized on gamma ray logs in Lagrange, Steuben, Noble, and DeKalb Counties. The Sunbury separates the greenish-gray shales of the Ellsworth from those of the Coldwater Shale. In areas where the Sunbury is not present, the Ellsworth cannot readily be separated from the overlying Coldwater Shale (fig. 2B).

STRUCTURE

A structure contour map on the base of the New Albany Shale and its equivalents was compiled from about 1,400 well records in the Illinois Basin and about 400 well records in the Michigan Basin. Where available, datum points were selected at a density of one well per section and contoured at a 100-foot interval. Figure 4, with a contour interval of 500 feet in the Illinois Basin, is a simplified version of the original map.

The New Albany Shale both thickens and dips into the Illinois Basin. In the outcrop belt the base of the formation is 500 to 600 feet above sea level. In extreme southwestern Indiana the base of the shale is 4,500 feet below sea level. Within 20 miles of the outcrop belt the rocks dip 20 to 30 feet per mile to the southwest; the dip increases basinward and is about 40 to 60 feet per mile in southwestern Indiana. This generally uniform southwesterly dip of the shale is disturbed locally by the Mt. Carmel Fault and by a series of small domal structures reflected upward from Silurian reefs.

The Mt. Carmel Fault in south-central Indiana is a normal fault downthrown on the west (basinward) side about 100 feet. Rocks on the basinward side of the fault are folded into a southward-plunging anticline in Monroe, Lawrence, and Washington Counties (fig. 4).

Silurian reef structures extend in a belt from Vigo and Clay Counties southward to Dubois County. The structures are generally about one mile in diameter and are represented on the New Albany structure map by small domal areas with 100 to 150 feet of closure. The New Albany thins slightly over some of the reef structures.

The base of the Sunbury-Ellsworth-Antrim interval in the Michigan Basin dips northward at 10 to 20 feet per mile beneath thick glacial drift or Mississippian Coldwater Shale. In northern Steuben County the base of the Antrim is approximately at sea level. No major faults or reef structures interrupt the northward dip, although there are several small flexures and local variations in strike and dip.

OCCURRENCE OF GAS

Gas has been produced from the New Albany Shale from seven fields in Harrison County, one field in Martin County, and two small fields in Daviess County (table 1). All fields are now largely abandoned except the one-well Bramble field in Daviess County. Figure 5 shows the distribution of these fields and of oil and gas shows in the selected study wells.

Of the some 1,400 study wells penetrating the New Albany Shale in the Illinois Basin, about 6 percent are reported to have had some show of gas from the shale. A clustering of gas shows is found along the Mt. Carmel Fault in Monroe, Lawrence, and Washington Counties, in western Greene County, and in Harrison County.

The random distribution of gas shows appears to have no relationship to structure. Although many gas shows have been reported in the Silurian reef belt in western Greene County, none of these shows have been correlated with a structural high over a buried reef despite the fact that there is significant oil and gas production from underlying Middle Devonian carbonates over these reef-induced structures (fig. 6).

Sorgenfrei (1952) noted the correlation of New Albany gas fields in Harrison County with "nose" or "dome" structures. Such a correlation is not seen on the scale and contour interval of the present map. The Loogootee North Field in Martin County (fig. 5) seems to have been associated with a small basin or syncline with a few tens of feet of closure (Sorgenfrei, 1952). Little correlation is seen between thickness of the shale and the occurrence of gas.

In Harrison County, gas in the New Albany has been generally produced in the upper part of the formation (Grassy Creek Member), or from a zone 20 to 30 feet above the base (Sorgenfrei, 1952). At the single-well Bramble Field in Daviess County, an initial production of 250 MCF/24 was obtained from the entire thickness of the unit. At the Glendale Field the single producing well yields gas from a zone seven feet thick near the middle of the unit.

Scattered shows have been reported from the Antrim Shale, but there are no producing wells in the Michigan Basin.

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Table 1. Data on gas fields in the New Albany Shale in Indiana
[Modified from Becker and Keller, 1976]

County	Field name	Discovery year	Number of wells	Average initial production	Average depth	Present status (1977)
Daviess	Bramble	1974	1	250MCF/24	1,700	Active
Daviess	Glendale	1940	1	750MCF/24	2,100	Abandoned
Harrison	Corydon	1923	15	110MCF/24	800	93% Abandoned
Harrison	Elizabeth	1925	1	Gas	750	Abandoned
Harrison	Laconia	1915	106	220MCF/24	700	99% Abandoned
Harrison	New Boston	1885	13	245MCF/24	450	85% Abandoned
Harrison	New Middletown	1923	26	120MCF/24	750	96% Abandoned
Harrison	Rosewood	1895	21	225MCF/24	300	90% Abandoned
Harrison	Rosewood North	----	4	Gas	300	Abandoned
Martin	Loogootee North	1902	12	780MCF/24	1,500	92% Abandoned

Figure 1. Map of Indiana showing counties.

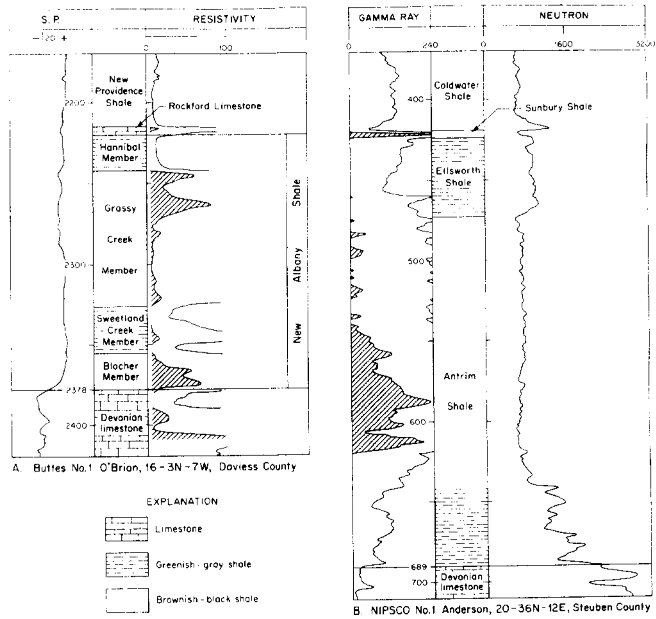

Figure 2. Geophysical log and stratigraphy of the New Albany Shale in the Illinois Basin (A) and of the equivalent strata in the Michigan Basin (B).

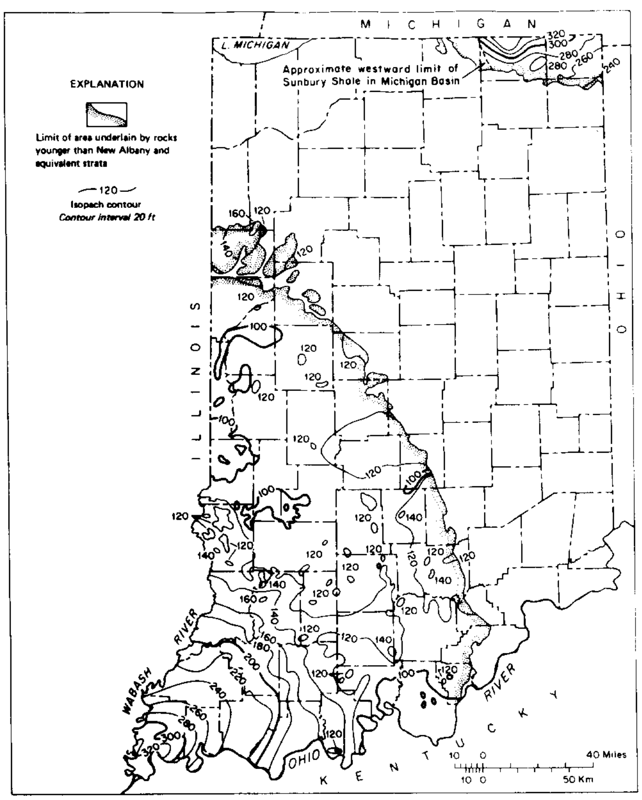

Figure 3. Isopach map of the New Albany Shale and equivalent strata in Indiana.

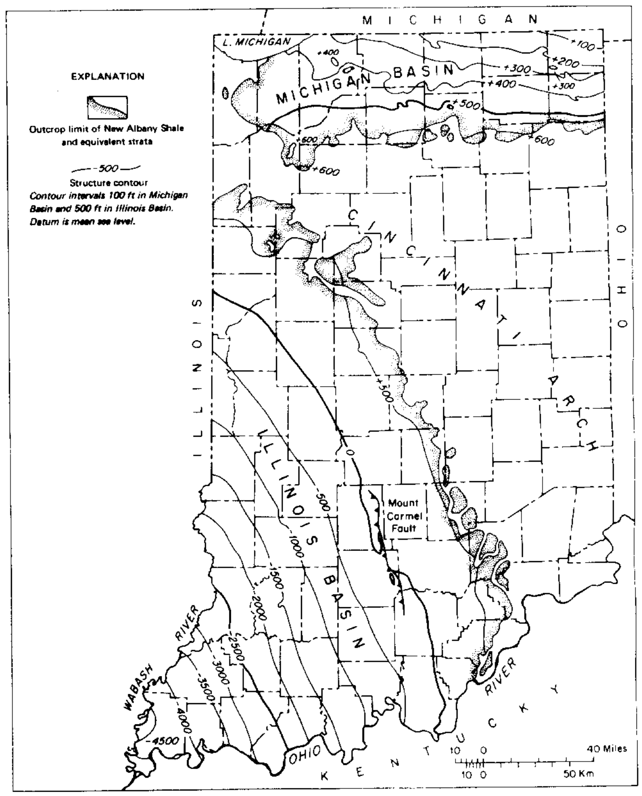

Figure 4. Map of Indiana showing structure on the base of the New Albany Shale and equivalent strata.

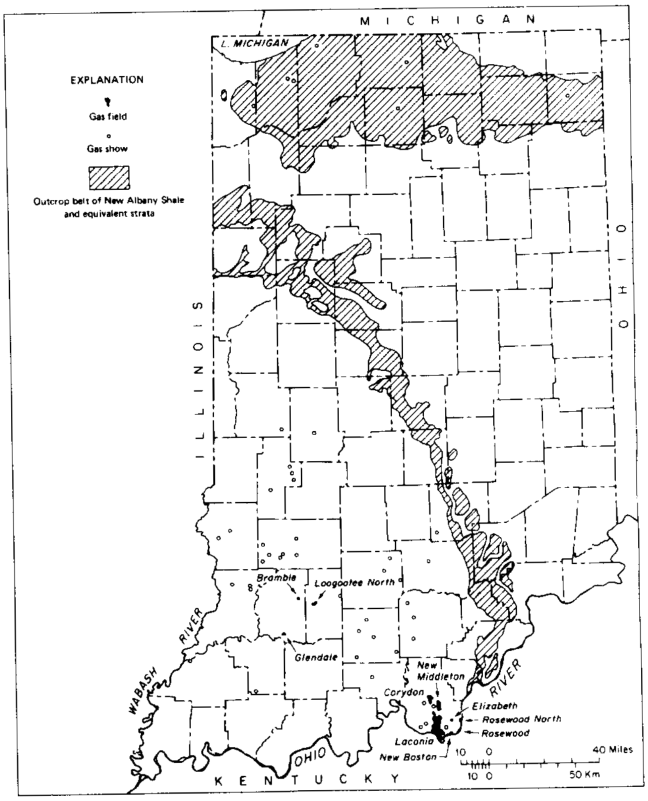

Figure 5. Map of Indiana showing gas fields and gas shows from the New Albany Shale.

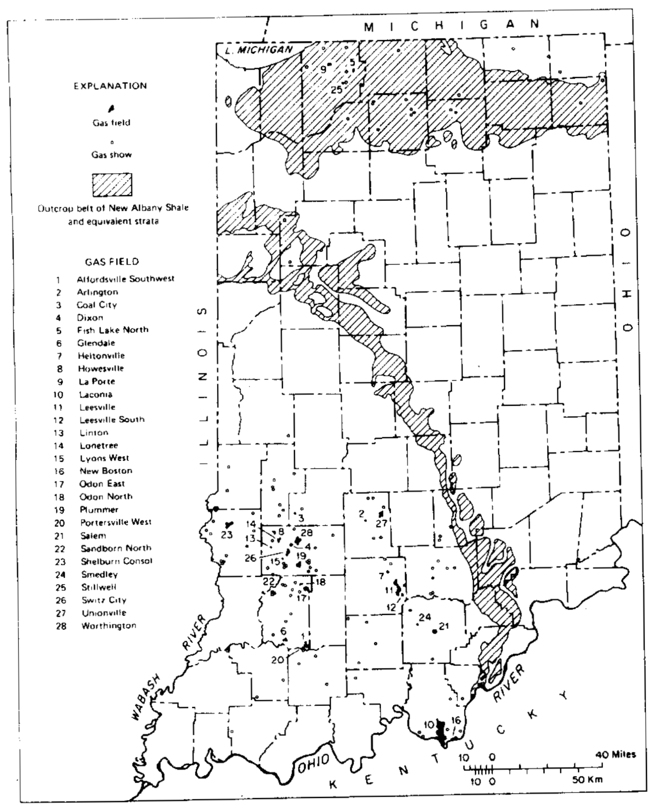

Figure 6. Map of Indiana showing gas fields and gas shows from the Middle Devonian limestone.

CHARACTERIZATION OF THE DEVONIAN SHALES AND EVALUATION OF THEIR ENERGY-PRODUCING POTENTIAL: SOME APPROACHES AND PRELIMINARY RESULTS[1]

by

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Abstract

On July 1, 1976 the West Virginia Geological and Economic Survey initiated an intensive 5-year study of the Devonian shales in West Virginia under a contract from the U.S. Energy Research and Development Administration. The objective of the project is to characterize adequately the shales and to determine accurately their total energy-producing potential including natural gas and oil, synthetic fuels, and radioactive minerals. The approach used is a detailed and integrated study of the stratigraphy, petrology, and geochemistry of the shales with the data synthesis and analysis accomplished with the assistance of the computer.

Tentative subsurface correlations have established a generalized stratigraphic framework for the Devonian shales in the producing areas of West Virginia which consists of four zones. In descending order they are: an upper interval which comprises about one-half of the total thickness of the shales (approximately 1200 feet) and consists of gray and greenish-gray shales with sandy and silty zones present; a dark gray to black interval, 400 feet thick, characterized by finer grain size, darker colors, and the presence of spores (this interval is called the "Brown shales" by the drillers and has produced most of the natural gas); a greenish-gray shale interval, 400 feet thick, which lacks silt and spores; and a lower black shale interval. The first reported occurrence of the fossil alga, Foerstia, is from the "Brown shale" zone in Lincoln County, West Virginia.

Lithologically, the core samples analyzed to date can be grouped into 6 rock types: shale, silty shale, dolomitic shale, shaly siltstone, dolostone, and shaly sandstone. Mineralogically, illite comprises the major part of the argillaceous fraction, whereas quartz constitutes the principal non-clay mineral. Carbonate is present in most specimens and is generally dolomite. The most prevalent heavy mineral is pyrite. Dark gray to brownish-black organic-rich shale constitutes the most distinctive rock-type in the principal "Brown shale" pay-zone interval. Organic matter occurs in several forms. Vertical, mineral-lined fractures are important in facilitating gas migration and accumulation in most pay zones. Dolomite is the

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1 Published with permission of the Director and State Geologist. Funded under U.S. ERDA contract no. EY-76-C-05-5199.

2 West Virginia Geological and Economic Survey, P.O. Box 879, Morgantown, WV 26505. Phone: AC 304 292-6331.

main mineral constituent in the fracture linings; however, small amounts of calcite and barite also are present. Mineral linings serve as propping agents to hold fractures open and thus are important in maintaining porosity and permeability along fractures. Lenses of silt-size quartz and feldspar within the shale may serve as conduits for migration of the gas from the matrix material into these fractures.

The geochemical phase of the study is divided into three basic parts: elemental characterization, mineralogical characterization, and basic organic characterization. Elemental characterization will be approached in two ways. Bulk rock samples will be prepared and subjected to wavelength dispersive X-ray spectroscopy to determine the concentrations of about 40 elements. These data will be combined with the petrographic and stratigraphic data in order to determine whether or not systematic stratigraphic variability exists for any one or combination of elements within the rock sequence. It also is anticipated that specific elemental distributions will be tested on an individual grain basis by employing the microprobe capability of the scanning electron microscope (SEM) in conjunction with the energy dispersive and wavelength dispersive spectrometers with which the SEM is equipped. Mineralogical characterization will be made by X-ray diffraction on the same samples submitted for bulk elemental analysis. Again, those data will be combined with the petrographic data and the stratigraphic data in order to test for systematic mineralogical variations. Mineral identification on the micro level and compositional phase variations will be investigated with specific mineral types by scanning electron microscopy and energy dispersive spectrometry. The basic organic characterization will be performed by a combination pyrolysis-chromatography. The intent is to provide a "fingerprint" characterization of the organic components of each selected sample. These data will, like the rest, be applied to a geochemical-sedimentological model in order to test whether or not the basic organic components vary within the rock section in some systematic fashion.

Although much work remains to be done, our present state of knowledge suggests that the best prospects for additional shale gas reserves are where thick dark shales occur over deep-seated faults which have been reactivated to produce natural fracture systems within the shale.

INTRODUCTION

The "Devonian shales" or "Brown shales" comprise one of the older, but least studied or understood reservoirs in West Virginia. Shales within this section have yielded natural gas for nearly 50 years from low-volume, shallow wells in the western one-third of the state, but until recently there was little interest by either industry or government in attempting to determine or develop on a major scale the potentially large energy resources of the Devonian shales in the Appalachian basin.

On July 1, 1976, under contract from the U.S. Energy Research and Development Administration as part of its Eastern Gas Shales Project, the West Virginia Geological and Economic Survey initiated an intensive 5-year program to characterize the Devonian shales in West Virginia and to evaluate their energy-producing potential. The approach to be used is an integrated and detailed stratigraphic, petrologic and geochemical study of the shales utilizing computer processing for data synthesis and analysis. The preliminary results of the study to date are briefly summarized in this paper. For more details the reader should refer to Larese and Heald (1977), Patchen (1977), Renton (in press), and Schwietering and Neal (in press).

STRATIGRAPHY

The "Devonian shales" comprise a thick sequence of fine-grained clastic rocks which occupy the stratigraphic interval between the base of the Lower Mississippian Berea Sandstone and the top of the Lower Middle Devonian Onondaga Limestone in the western one-third of the state. The term "Brown shales", although often used by drillers as a synonym for the Devonian shales, is more correctly restricted to darker, organic-rich shales within the thicker overall Devonian clastic interval. The total thickness of the Devonian clastic interval varies from less than 1000 feet in the gas-producing areas of the southwestern part of the state to more than 7000 feet in the north-central subsurface area of the state and up to 10,500 feet in the eastern outcrops. However, the portion of that overall interval that consists of black or dark-gray shales (so-called "Brown shales") is much less, ranging from 10 to 60 percent of the total interval in the southwestern part of the state where there is currently gas production. Although the dark shales thicken to the east they comprise a smaller percentage of the total shale section and occur at greater drilling depths (Figure 1).

Based on lithology as determined from drillers' logs, sample studies and geophysical logs, Patchen (1977) has established a general 4-fold subdivision of the Devonian shales in the gas-producing area. In descending order the four recognized subdivisions of the Devonian shales are:

a) An upper 1100- to 1200-foot interval consisting of gray and greenish-gray, sandy silty shales. The lower 400 feet of this interval contains less silt and the uppermost spore-bearing dark shales.
b) A 400-foot interval consisting of upper and lower dark gray to black shale zones (called "Brown shale" by the drillers), separated by a medium gray, often silty shale zone. The silt content of the dark gray to black shales generally decreases as the upper and lower shales become darker. Spores are often noted within these two dark shales. Schwietering and Neal (in press) have described the first reported occurrence of the fossil alga, Foerstia, from the Brown shale zone in Lincoln County, West Virginia.
c) A 300- to 400-foot interval of greenish-gray, usually non-silty shales. This persistent interval can be traced over 100 miles from eastern Kentucky (where it is referred to as the Big White Slate by drillers) northward into Wood County, West Virginia.
d) A lower, very dark gray to black shale interval which ranges

from 200 to 400 feet in thickness. These older dark shales are in general darker than the younger dark shales in the "Brown shales" zone and are often calcareous in the lower 100 to 200 feet of the interval. A thin limestone is often noted within the lowest black shale and is usually referred to by drillers as the Tully Limestone.

Farther to the west and southwest a younger Brown shale is present near the top of the youngest zone in the approximate stratigraphic position of the Cleveland Shale of Ohio. In north-central West Virginia numerous sandstones and siltstones replace much of the shale section, in particular the so-called Brown shales.

PETROLOGY

Based on petrographic analyses of forty selected core samples of Devonian shale from two wells in western and southwestern West Virginia, Larese and Heald (1977) grouped the samples into 6 rock types: shale, silty shale, dolomitic shale, shaly siltstone, dolostone, and shaly sandstone, with most samples being shales and silty shales. Modal analyses indicate that the shales average 89 percent clay-size material, 9 percent silt-size quartz-feldspar, and 2 percent carbonate, whereas the silty shales average 65 percent clay-size material, 32 percent silt-size quartz-feldspar, and 3 percent carbonate. Mineralogically, illite comprises the major part of the argillaceous fraction, whereas quartz constitutes the major non-clay mineral. Carbonate is present in most specimens and is generally dolomite. The most prevalent heavy mineral is pyrite.

The color of the shales in hand specimen ranges from greenish gray to black. In thin section the shale is much lighter in color, ranging from light tan to dark brown. The brown color of the shales is due to organic matter which comprises as much as 4.4 percent by weight of some samples. The organic matter occurs in several different forms: finely divided matter which imparts a reddish-brown color to argillaceous material as seen in thin section, irregular reddish-brown shreds which may represent woody material, and discrete organic bodies such as spores.

In the pay zones of both wells, mineral-lined, vertical fractures were commonly noted. There appears to be considerable dispersion in their orientation within the pay zone. Vertical, mineral-lined fractures are believed to be very important in facilitating gas migration and accumulation in most pay zones. Dolomite is the main mineral constituent in fracture linings; however, small amounts of calcite and barite also are present. Except where vein filling was complete, mineralization may have been very important in maintaining openings along fractures through the propping action of minerals growing out from the walls of the fractures.

In very dark, organic-rich shale specimens, clastic silt-size quartz and feldspar are commonly segregated into lenses parallel to bedding. Although not easily seen in hand specimen, these silt lenses are readily apparent in thin section and commonly occur at regular intervals in otherwise homogeneous appearing shales. These lenses probably have higher permeability than the shale and, therefore, may serve as conduits for the migration of gas from the shale matrix to fracture zones where much of the gas ultimately accumulates.

GEOCHEMISTRY

The geochemical phase of the study involves three basic parts: elemental characterization, mineralogical characterization, and basic organic characterization. To date most of the work accomplished in this phase of the study has been in mineralogical characterization of the shales for petrologic investigations. Renton (in press) has described the use of uncorrected X-ray data in semi-quantitative analytical determinations. Only a very minor amount of elemental or basic organic characterization has been accomplished to date. However, the following paragraphs present a brief description of the approaches to be used and some of the goals of this phase of the study.

Bulk rock samples will be prepared and subjected to wavelength dispersive X-ray spectroscopy to determine the concentration of about 40 elements. These data will be combined with stratigraphic and petrologic data in order to determine whether or not systematic horizontal or vertical stratigraphic variation exists in any one or combination of the elements within the rock sequence. Sepcific elemental distributions within individual mineral grains will be determined by using the microprobe of a scanning electron microscope in conjunction with its energy dispersive and wavelength dispersive spectrometers.

Mineralogical characterization will be accomplished by X-ray diffraction utilizing the same samples that were used for bulk elemental analysis. These data also will be combined with petrologic and stratigraphic data to determine whether systematic mineralogical variation exists within the shales. Mineral identification at the micro level and compositional phase variation will be investigated for specific mineral types by scanning electron microscopy and energy dispersive spectrometry.

The basic organic characterization of the shales will be accomplished by a combination of pyrolysis-chromatography to provide a "fingerprint" characterization of the organic components of each selected sample. These data also will be tested for systematic variability within the shales.

DATA PROCESSING

All data from the stratigraphic, petrologic, and geochemical phases of the project will be synthesized and analyzed with the aid of the computer through various statistical, mapping, and other graphic programs. The computer-generated information will be combined with other standard geological methods of interpretation in order to arrive at the best interpretation of the depositional, diagenetic, and tectonic history of the Devonian shales. That, in turn, when combined with characterization data will permit an accurate appraisal of the total energy-producing potential of the shales and point the way for the best exploration and completion technologies to be used for future development of that potential.

EXPLORATION AND FUTURE RESEARCH

Although a generalized stratigraphic framework has been established for the Devonian shales in West Virginia and their major lithologies have been described, much work remains to be done to determine accurately the detailed correlations and facies relationships within the shales as well as their detailed petrology and geochemistry. At present, mapping of areas of thick dark shales (Brown shales) is a major exploration tool. The importance of natural fractures within the shales to gas production also has been recognized. The outline of Brown shale production in West Virginia coincides strikingly with the trend of the Rome trough (Figure 1). It has been postulated (Martin and Nuckols, 1976) that fractures in the Devonian shales in the gas-producing areas result from reactivated movement of the basement fault blocks that comprise the Rome trough. Therefore, our present state of knowledge suggests prime areas for future exploration for Devonian shale gas reserves should be where thick dark shales overlie the Rome trough or similar structural features. Much additional work remains to be done on the exact nature, cause and timing of the fractures as well as their relation to regional stress and structural patterns below, within, and above the Devonian shales.

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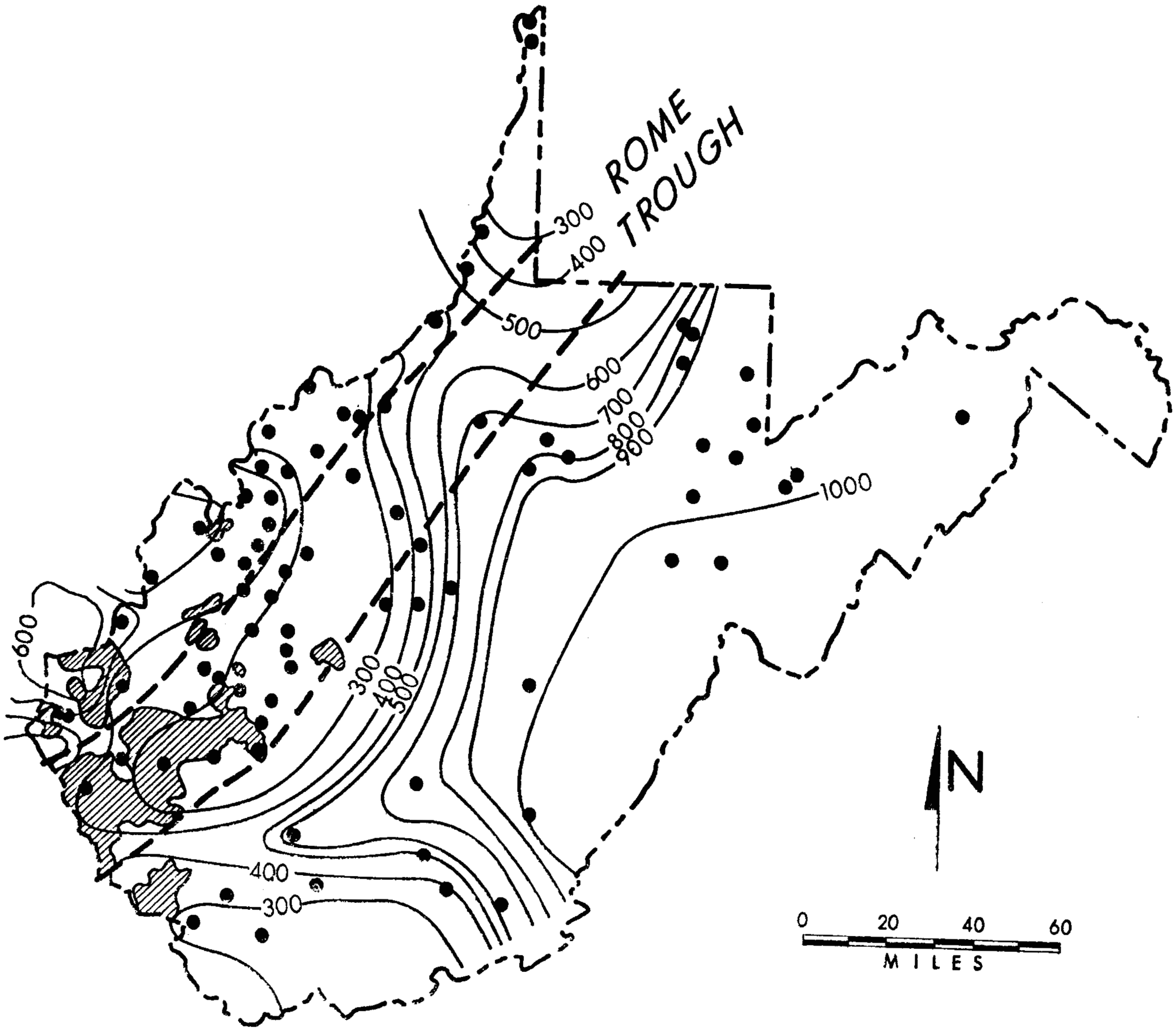

Figure 1. Devonian shale gas fields, thickness of dark, organic-rich shales within the Devonian shales, and approximate position of the Rome trough in West Virginia (from Patchen, 1977).

ANALYSIS OF STRUCTURAL GEOLOGICAL PARAMETERS THAT INFLUENCE GAS PRODUCTION FROM THE DEVONIAN SHALE OF THE APPALACHIAN BASIN

by

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ABSTRACT

The Department of Geology and Geography at West Virginia University is studying the structural parameters that may affect gas production from the Devonian shale in southwestern West Virginia and eastern Kentucky. The project is designed to (1) document fracture patterns and structural deformation within and around areas of Devonian shale production; (2) evaluate inexpensive geophysical and remote sensing techniques to locate potentially productive fracture zones; and (3) study production within producing fields for comparison with adjacent non-productive areas to assess the influence of structure on production.

Work was initiated this year on regional analysis of basin structures, compilation of surface fractures from eastern Kentucky and West Virginia, shallow high frequency seismic and resistivity studies to locate fracture zones and groundwater studies above the Cottageville Devonian shale gas field for comparison with a production study of that same field.

OBJECTIVES

The general object of our project under contract E(40-1)-5194 is to study the structural parameters of the Devonian shales that effect gas production in eastern Kentucky and West Virginia (Fig. 1).

Prepared for the Energy Research and Development Administration, under Contract No. E(40-1)-5194.

To that end, our program is specifically designed to:

1. Collect, compile, and analyze geologic data to construct regional structure maps of eastern Kentucky and West Virginia.

2. Determine if structural types and styles effect production and determine if minor structures as mapped in outcrop could influence production characteristics.

3. Determine if shallow seismic surveys can detect near-surface faults and fracture zones, and if the structure can be detected to further determine how such fractures relate to both production from the shale and to lineations observed on remotely sensed data.

4. Determine if a relationship exists between ground water movement and shale gas productivity.

Through the integration of our work with others it is our ultimate goal to discover if relationships exist between Devonian shale gas production and geologic structure. If such a relationship is established, we will attempt to develope a method or methods for selecting favorable sites to drill shale wells that have a higher potential for gas production than the norm for that region.

MAJOR RESULTS

The major results of our effort have been:

1. The preparation of preliminary regional structure maps on several horizons across the study area.

2. The initiation of a regional fracture mapping program of a portion of the study area.

3. The design of shallow high-frequency seismic equipment to map shallow fracture zones.

4. The initiation of production studies of the Mount Alto (Cottageville) West Virginia Devonian shale gas field.

GENERAL PROGRAM

A major part of our effort during the first year of this comprehensive study has been spent in recruiting and hiring qualified personnel, accumulating structural and production data for analysis, and ordering and designing seismic and remote sensing equipment.

In order to attain the objectives of our contract, the investigation has been divided into several study groups. The purpose of each study group is listed below followed by a brief description of the general tasks and accomplishments of personnel in that group. Not all planned tasks have been started the first year because delay is necessary to integrate and coordinate certain tasks of our contract with those of other contract groups. Other tasks have been delayed as they require the results of preliminary work of other study groups to be available before an effective work plan can be designed for embarking on a second task.

Regional Structure Studies

The primary task of this group is to collect data and construct maps that will provide a regional structural framework for eastern Kentucky and West Virginia (Fig. 1). Naturally, it is important that the regional structure background be available for the primary producing area of the Devonian shale gas. In order to evaluate the importance of geologic structure on production and in order to compare structure with the results of other geologic or geochemical investigations. The standard 1:250,000 map scale will facilitate such comparisons.

This study will progress along three lines:

1. Compilation and interpretation of basin structure

2. Compilation and interpretation of regional fracture patterns

3. Compilation and interpretation of minor structural features as mapped in the outcropping Devonian shale.

Results as of July 1977 are as follows:

1. Preliminary structure maps (scale 1:250,000) have been compiled for the top of the Precambrian basement, the base of the Onondaga and the top of the Berea for part or all of the study area. Maps (scale 1:250,000) showing the general outline of production from the Devonian shale have also been compiled for eastern Kentucky and West Virginia.

2. Compilation of lineaments, joints, and in-situ stress measurements has begun, and field work to collect fracture data has been started in eastern Kentucky. As fractures and lineaments are delineated (in part under a separate grant #E(40-1)-8040) comparison will be made with the production data being compiled in another study group (see Production Studies below). As a part of this program we are mounting a multispectral camera in a low-altitude aircraft to obtain imagery over producing areas to use the imagery for fracture trace analysis.

3. Outcrop studies of micro-structure found within the Devonian shale will be undertaken in conjunction with similar studies planned for adjacent states by the U.S. Geological Survey. These studies will be initiated in the fall of 1977.

Production Studies

It is our feeling that there is perhaps nothing more important to the entire shale project than the compilation and analysis of gas production from shale gas fields is essential to the project if the results of all types of research are to be evaluated against the practical yardstick of shale gas production.

The Mount Alto (Cottageville) field was selected as the initial field study area because the primary operator within this field, the Consolidated Gas Supply Company, has already initiated a study of that field and has established a close working relationship with ERDA. We found a very cooperative attitude prevalent for all operators in that field so that production data is now available and is being compiled for analysis from the files of several other gas companies operating in the field. Preliminary results of this analysis may be ready for oral presentation at ERDA's first Eastern Gas Shales meeting in October.

Our plans call for expanding Production Studies into other areas of West Virginia and eastern Kentucky wherever production data are available in sufficient detail and warrent such studies.

In addition to our detailed analysis of gas production we have also initiated a shallow groundwater investigation in the Mount Alto field area. The possibility that a relationship exists between groundwater yields and deep gas production from the shale is based on the premise that fracture porosity, which often enhances groundwater production may also affect production from the underlying shale. While the likelyhood of such an interrelationship may be small, it is possible and, therefore, should be evaluated. If the production characteristics from the two different reservoirs are similar, then groundwater production could be used as a lead to locating more productive shale gas wells.

Geophysical Studies

Several geophysical methods have the potential to locate shallow fracture zones. In the case of shale gas, any geophysical method adopted by operators to locate fractures must not be expensive because the marginal economics of shale gas production demands frugality in exploration procedures.

Our research program investigates if inexpensive shallow penetration, resistivity and seismic devices can readily locate fracture zones at low cost.

Three areas (Fig. 1) have been selected to test resistivity and seismic equipment against known shallow fracture zones. The purpose of modifying standard low-frequency seismic equipment to high-frequency investigations is an attempt to more precisely define bed boundaries to determine if those fractures and faults with minor offsets can be identified. If the fracture zones at the three test sites can be identified by any one of the several methods to be tested, then we intend to study the Mount Alto (Cottageville) shale gas field and selected lineaments within the Devonian shale gas producing area in detail to determine if a correlation exists between fractures, lineaments and shale gas production.

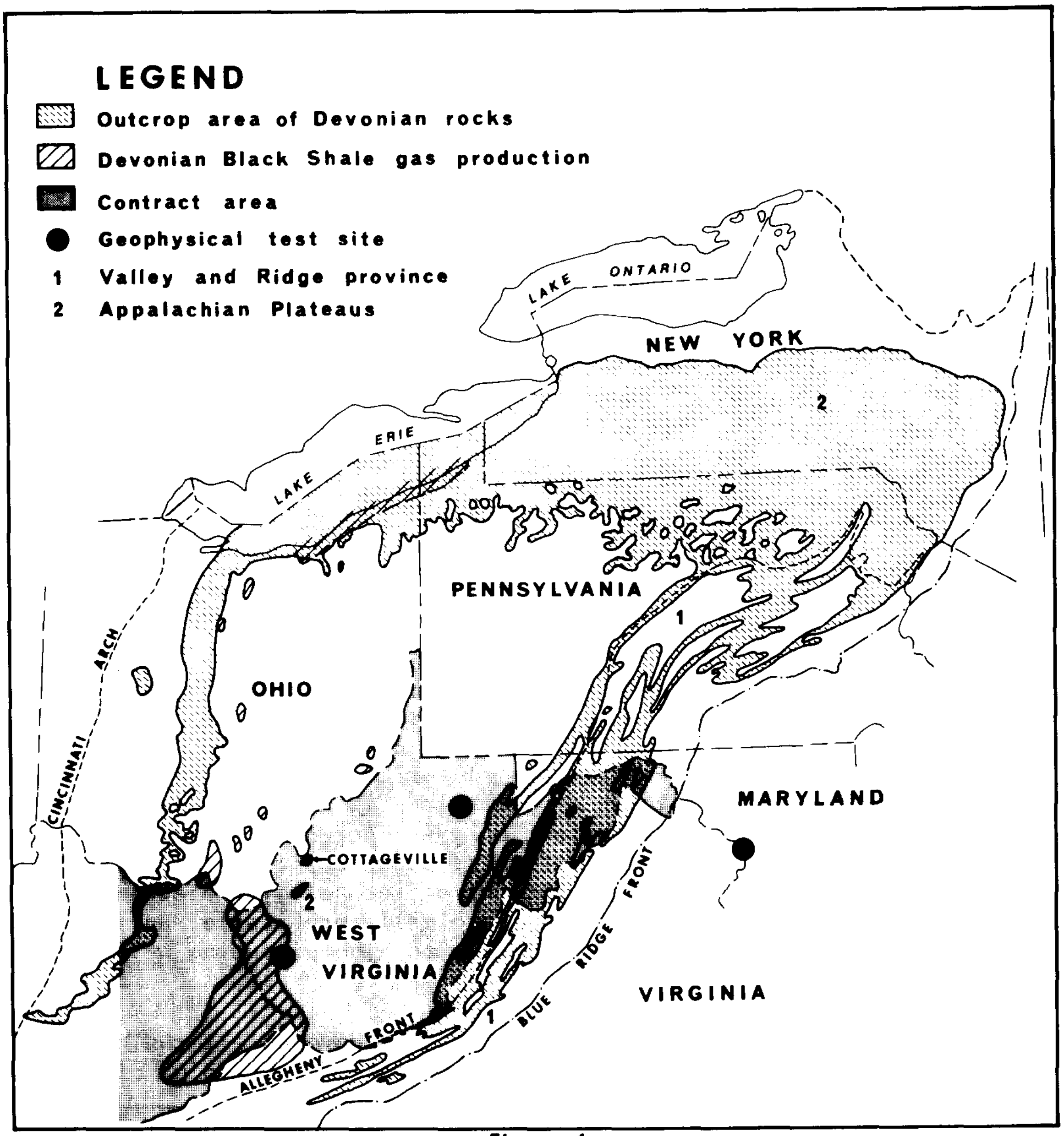

Figure 1

REMOTE SENSING METHODS FOR APPLICATION TO NATURAL GAS PRODUCTION FROM FRACTURED DEVONIAN SHALE RESERVOIRS OF WESTERN WEST VIRGINIA

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ABSTRACT

Natural gas production from the Devonian black shales of the Appalachian Basin is from fracture permeability. The possibility that wells drilled on zones of increased fracturing may be better producers coupled with the fact that some fracture zones are visible on remote sensing imagery as photolineaments initiated this project. Photolineaments were mapped from various types of imagery, and natural gas initial production data were obtained from driller's logs. The relation between initial production data and proximity to various types of photolineaments for the gas wells indicates that such relationships are very complex.

INTRODUCTION

A significant fraction of all hydrocarbon production is from wells which either have intersected natural fractures or which have had artificial fractures produced in them. Such production comes from formations which, although "tight", have considerable hydrocarbons trapped in intergranular porosity. These formations have such low intergranular permeability that the hydrocarbons, even natural gas, can only be produced economically from fractures. The Middle and Upper Devonian black shales of the Appalachian Basin which underlie the Plateau and eastern Continental Interior physiographic provinces are excellent examples of the fractured reservoir. It has been estimated that as much as 460 quadrillion cubic feet of gas - potentially 200 to 300 years supply - may be in these shales; of this, about 285 trillion cubic feet could be extracted under expectable conditions of technology and economics.[1] Since most of the wells are presently only marginally profitable, any exploration technique which decreases the ratio of low to high producing wells would increase the recovery.

The aim of the present project is to ultimately develop a technique for planning wells which uses low-cost remote sensing methods. Mapping of fractures

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References and illustrations at end of paper.
Prepared for the Energy Research and Development Administration under Contract No. E-(40-1)-8040.

and use of such maps in planning well fields has been a routine procedure in many areas. Normally photolineaments are mapped from air photos, satellite imagery, and any other type of imagery available. *Photolineaments* are continuous linear or curvilinear features or alignments of discrete features which can be detected on aerial photographs or other imagery.[2] Such procedures have been found to be of significant aid in some arid terrains such as those of northern Africa or southwestern Asia. In the United States, photolineament mapping has been successfully used as an exploration tool by Columbia Gas in their Haysi Field in western Virginia and southeastern Kentucky. Here it was found that for wells producing from the tight Berea siltstones, those wells drilled on or near photolineaments produced at about twice the rate as the other wells.[3] The potential usefulness of the photolineament mapping procedures in fractured reservoirs is not restricted specifically to siting of wells. A relationship has been demonstrated among the orientation patterns of photolineaments, surface fractures, subsurface fractures, and regional stress fields.[4] Thus, even if specific siting cannot be done, the techniques can still be used for predicting induced fracture orientation in various stimulation procedures.

METHOD OF STUDY

Regional photolineaments were mapped from satellite imagery at scales of 1:1,000,000 and 1:5,000,000. Local patterns were mapped at various scales, but most commonly at 1:250,000 (the standard scale of the Eastern Gas Shales Project). Surface fractures (joints) were measured on outcrops in selected areas; orientation patterns were plotted; and preferred orientation directions determined. Initial gas production figures were obtained from driller's logs on file with the West Virginia Geological and Economic Survey.

The area chosen for this study consists of portions of West Virginia and eastern Kentucky with small adjacent portions of Virginia and Ohio also included.(Fig. 1). The reasons for choosing this area have been outlined previously.[5] Briefly, the area is one of interest since it is different from other areas where remote sensing methods have previously been applied in either geology or topography, and because it is underlain by the Devonian has shales. Two counties of West Virginia were also chosen for detailed study: 1) Jackson County, which contains most of the Cottageville (Mount Alto) Gas Field and has been the scene of intensive investigations by personnel from the Morgantown Energy Research Center (MERC) and others; 2) Wayne County, which has passing through it several major photolineaments associated with the 38th Parallel Lineament and also has available a considerable amount of initial production data for Devonian shale gas wells.

RESULTS AND CURRENT STATUS

This is the third and last year of this project. This report is being prepared as much of the data gathered during the preceeding year is being analyzed and results are not yet available. A full discussion will be available in the final contract report (contract termination date - 30 September) and a summary will be presented at the First Eastern Gas Shales Symposium.

Results of previous years have already been reported;[5] only brief summaries of the current year will be given here.

Data Analysis Procedures

Last year it was discovered that the Wald-Wolfowitz Runs Test could be used to compare orientation data distributions (i.e., rose diagrams of photolineament or joint trends). Subsequently, other tests were evaluated and one, Kuiper's modification of the Kolmogorov-Smirnov Test[6] was adopted for use in some of the statistical analyses. A computer program to plot orientation diagrams and to provide the statistical analyses of the data distributions was completed. Additionally, a general mapping computer program to aid in the analysis of the various types of data utilized by this project was completed. A discussion of the characteristics of these programs is beyond the scope of this report, but they will be fully described in the contract final report.

Relation of Photolineaments to Geological Features

This year's effort in terms of this phase of the project consisted of collecting data on joints and comparing this with large-scale photolineament maps. Measurements of orientation and other properties of fractures on outcrops are the primary field data utilized in this project. A relationship between orientation of fractures in surface outcrops and fractures in subsurface hydrocarbon reservoirs has been established for some areas.[7] There is also a relationship between surface fractures and photolineaments in some areas.[8,9] In the final report of this contract, there will be a more extensive discussion of these relationships; only a brief example of problems encountered and results obtained will be given here.

Problems encountered. In Jackson County (Fig. 1 shows location), the surface rocks are of the Permo-Pennsylvanian Dunkard Group which is primarily a deltaic sequence consisting of gray and red mudstones, siltstones, and channel and bar sandstones. The most prevalent outcrops are of the sandstones. There are several reasons why fractures measured on these sandstones may not be reliable indicators of regional fracture patterns. The sandstones tend to be relatively small patches surrounded by the mudstones. This leads to two conditions. First, regional fractures may not be propagated through the mudstones into the sandstones. Thus, fractures seen in the sandstones may well be due to fracturing of a brittle mass only poorly supported by the surrounding rather weak mudstones and so breaking up under its own weight. Second, the irregular shapes of the sandstone bodies can cause refraction in a propagating fracture and so change its direction. In this case although the fractures are related to regional fracture patterns, the directions found tend to differ from that pattern.

The effects of these problems are partially reduced by a regional analysis using several thousand measurments. With this quantity of data, errors introduced by factors active in small areas are eliminated or greatly attenuated. In any case, however, any analysis cannot depend on a *small* error margin.

Results. Figure 2 shows the most important preferred orientations at outcrops in Jackson County in the general area of the Cottageville Gas Field. The rosettes show the main peaks at each individual outcrop and the network of lines describes the approximate interpolation between these outcrops of the probable regional orientations of surface fractures. Figure 3 is a summary of the more prominent photolineaments of the same area as the joint measurements. A comparison of figures 2 and 3 shows that several of the trends are coincident. The major preferred directions on both diagrams are approximately the same. There is, however, clearly not complete agreement between the two patterns. Assuming a relationship between the two types of features, the disagreement between the two sets of orientations could be caused by either 1) the distortions of joint directions by sand lenses as outlined above, or 2) a difference in reaction of the short (joints) and long (photolineaments) features to regional stresses which may have varied in direction. There is, however, too much coincidence of the orientations of the two sets of data for it to be ignored entirely. Thus, it appears that the photolineament maps may serve to at least partially predict surface outcrop fracture directions. The additional step of predicting subsurface fractures induced during stimulation of wells is less certain because of additional restrictions placed on their formation by conditions under which they form.

Relation of Initial Gas Production and Photolineaments

A considerable amount of raw data has been gathered but at this writing, only a small amount for Wayne County has been analyzed.

Problems encountered. Both the photolineament and the gas initial production data presented problems. The gas production figures were derived from driller's logs on file with the West Virginia Geological and Economic Survey. The information on such logs is of variable quality. Often it is difficult to determine the source formation of the gas produced. It is possible also that some of the gas production ascribed to the Devonian shale may come from another formation. Thus, despite attempts to eliminate errors of this nature, it is entirely possible that such errors nevertheless remain in the data. Most wells actually were not used at all because production data was not given or because it clearly included production from horizons other than the Devonian black shales.

Photolineament mapping presents many problems. Affecting the analysis most is the choice of imagery type and scale which in turn affect the type of photolineament mapped. If too large a scale of imagery is chosen, the map which results will have so many lines that it approaches the appearance of "a yard filled with chickens scratching in the dirt." Such "chicken-scratch" maps would tend to have some photolineament "near" almost any point and any kind of analysis depending on relative locations would probably be meaningless. (This type of map is not totally useless, however, since the orientation patterns can still be used.)

Results. In light of the above-mentioned problems, a test analysis was done for Wayne County. Production test figures of both before and after shot tests were collected from 175 wells and plotted relative to photolineaments derived from satellite images. No clear picture emerged in relation to the after-shot production tests, but this may be due to the limited nature of this test case. In the case of the before-shot data, however, an unexpected relationship did appear. In all cases, wells showing high levels of natural open flow did not fall *on* or *very* near to the photolineaments. An explanation which has been advanced for this relationship is that if the photolineaments are indeed representative of zones of more intense fracturing, then the gas in these zones may have been vented to the atmosphere through open fractures which reach the ground surface.

FURTHER WORK

Considerable data analysis still remains to be done on this project. Natural gas production data will be compared with photolineament maps for the remainder of the area of Devonian shale production in the study area. Further compilation of field data and its integration into the analysis is also to be done.

It is intended that this project (at least for the study area):

1) State the effects of photolineaments on production of hydrocarbons, in particular, natural gas.
2) Predict sites which are favorable for drilling wells, taking into account both geological structure and fracture systems.
3) Provide information on natural fracture systems to aid in planning efficient well fields, and derive that information from imagery as the primary source.
4) Provide appropriate analysis tools for further, more extensive studies of the same general nature as the present project.
5) Predict orientation of induced fractures produced in fracturing operations.

It now appears that (5) above will not be possible due to unavailability of sufficient data on induced fractures within the study area.

We hope to be able to provide the techniques to derive the kind of information useful to the exploration for natural gas using imagery with only minimal field checking. Additionally, we hope to develop the techniques to the point where they may be used with confidence by others.

ACKNOWLEDGEMENTS

The work in this project was supported initially by U. S. Bureau of Mines Grant G0155011 and is currently supported by U. S. ERDA Contract E-(40-1)-8040. Thanks are due Robert C. Shumaker and Russell L. Wheeler of the Department of Geology and Geography of West Virginia University and William K. Overbey, Jr. and Clyde Pierce of MERC-ERDA for their advice.

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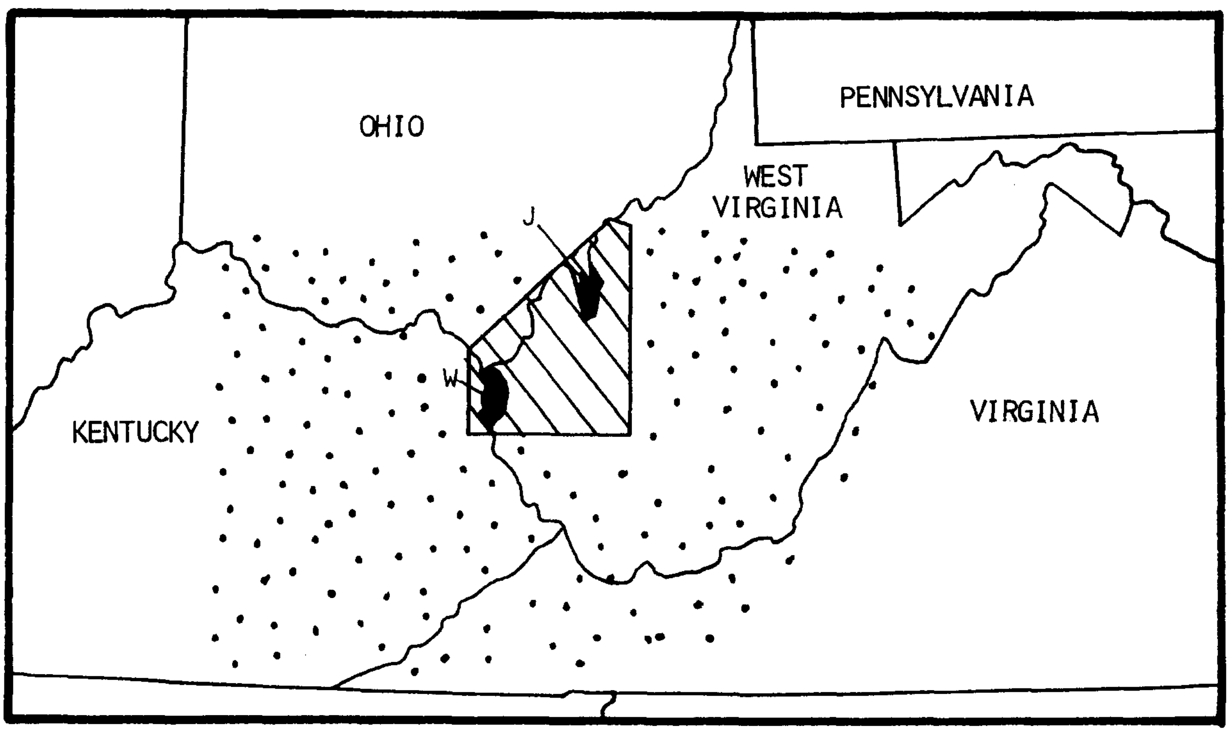

Fig. 1 - Area of study. The overall photolineament study covers the area shown in stipple pattern, the area in West Virginia underlain by the Devonian gas shales is approximately shown by the shading. J - Jackson County, W - Wayne County.

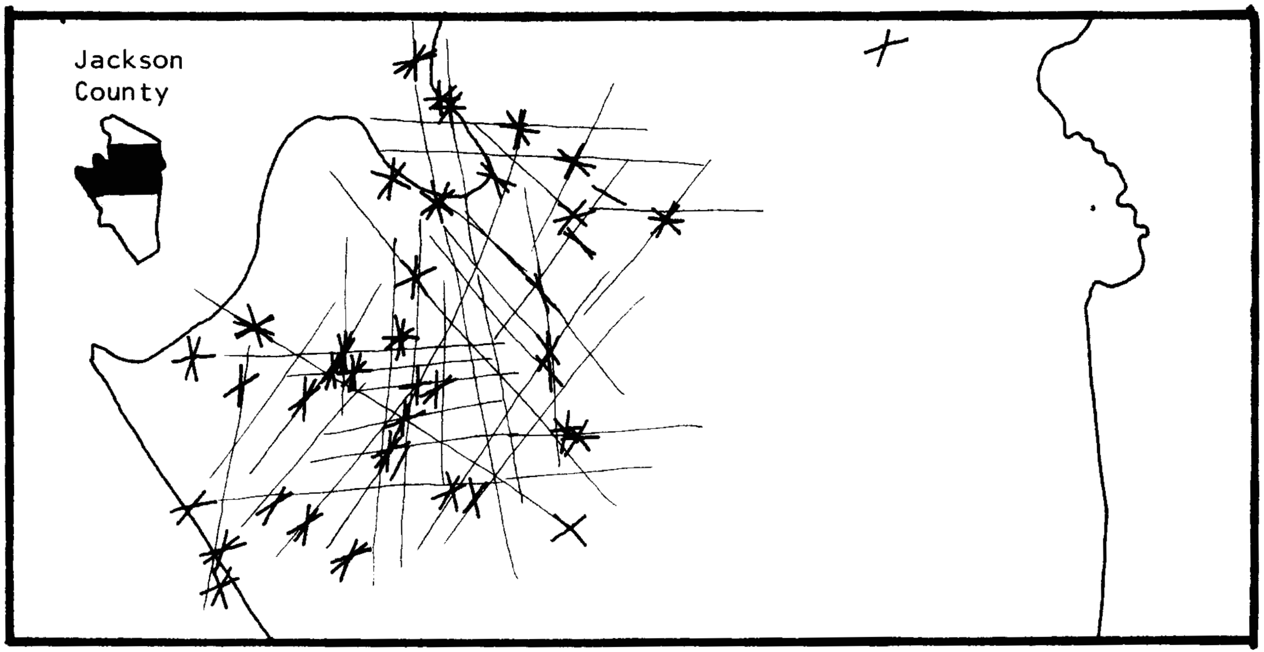

Fig. 2 - Joint patterns in part of Jackson County, West Virginia. The rosettes indicate the orientation peaks at individual outcrops. Light lines are interpolations of these directions between outcrop and are probably indicative of the regional trends.

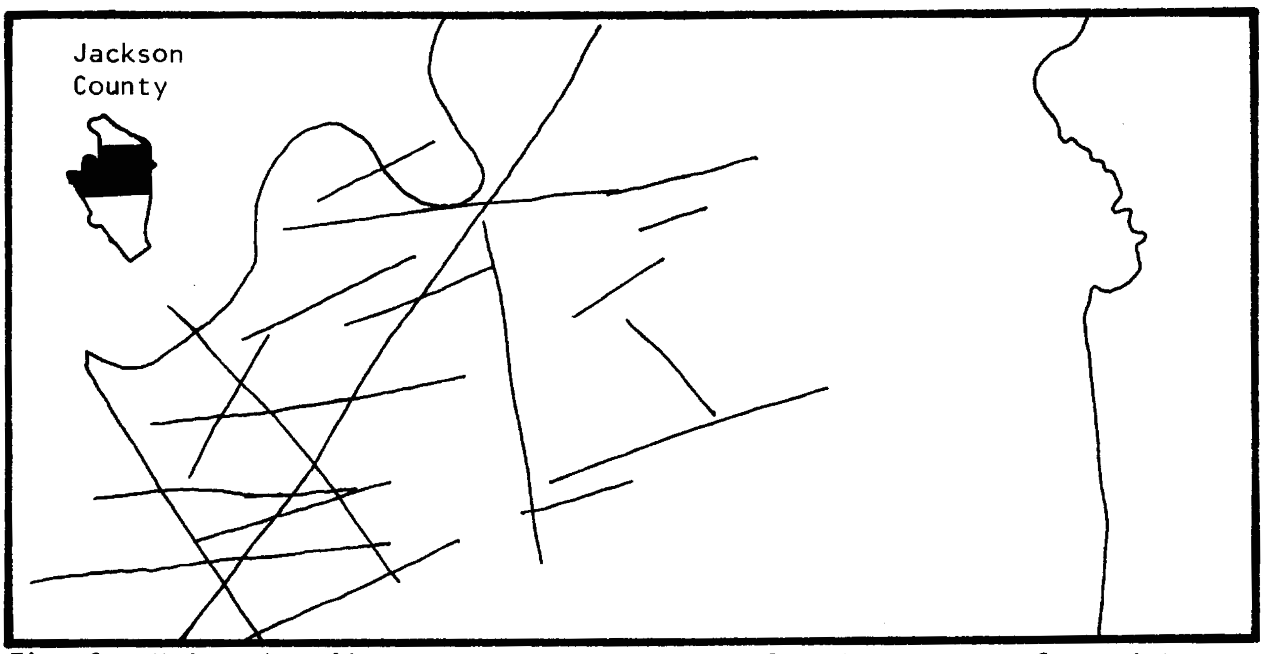

Fig. 3 - Major photolineaments in the portion of Jackson County for which joint data is shown in figure 2. Photolineaments are derived from Skylab and LANDSAT imagery. Photolineaments shown are visible on two or more of four different images used.

ASSESSMENT OF THE DEVONIAN SHALES IN THE APPALACHIAN BASIN FOR OIL AND GAS USING GEOCHEMICAL DATA

by

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ABSTRACT

Mound Laboratory, a prime Energy Research and Development Administration contractor, is performing detailed geochemical and geophysical studies on the Devonian Shales located in the Appalachian Basin. This study is part of the Eastern Gas Shales Program which is being directed by the Morgantown Energy Research Center.

The geochemical analyses are being used to provide an accurate assessment of the oil and gas resources present in the shales. They delineate the geochemical zones within the shale intervals penetrated by wells, and they define the exploration significance of the wells with respect to natural gas production from the Devonian Shale formation.

The detailed geochemical analyses of the shale intervals of three wells have been completed, and the results of these studies have been used not only to assess the gas present in the shale but also to evaluate the richness and the type (oil, condensate, or gas), of the sediments penetrated by these wells.

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*Mound Laboratory is operated for the U. S. Energy Research and Development Administration by Monsanto Research Corporation (Contract No. EY-76-C-04-0053).

Note: Copies of this paper are available from the author.

THERMAL MATURITY AND ORGANIC FACIES OF DEVONIAN SHALES FROM SELECTED WELLS

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ABSTRACT

An organic geochemical study was performed on core samples of the Devonian shale from wells in Ohio, Kentucky, and Illinois. The thermal maturity of the organic matter (kerogen) contained in the fine-grained sediments was investigated by vitrinite reflectance and kerogen coloration (Thermal Alteration Index). The results indicate that the organic matter has been thermally matured to the early stages of petroleum and associated gas generation.

A suite of geochemical analyses designed to evaluate the organic richness, the hydrocarbon potential for gas, condensate, and/or oil, and the type of organic matter was performed on the samples analyzed for thermal maturity. In general, two types of organic facies were encountered. The rich organic facies (A) are characterized by abundant gas, gasoline, and gas-oil hydrocarbons, a high organic carbon content, and

*Mound Laboratory is operated by Monsanto Research Corporation for the U. S. Energy Research and Development Administration under Contract No. EY-76-C-04-0053.

organic matter prone to generate abundant oil and associated gas. Based on the geochemical data, a second type of organic facies (B) interbedded with the rich organic facies (A) was encountered in Kentucky and Ohio wells. Organic facies B consist of sediments relatively lean in organic carbon and gas-oil hydrocarbons, and abundant gas and gasoline hydrocarbons. In most cases, facies B are composed of woody and coaly types of kerogen. The woody-coaly kerogen is presumed to indicate a nonmarine derived depositional source prone to generate predominately gas (methane).

INTRODUCTION

Core samples from four wells drilled in Ohio, Kentucky, and Illinois have been analyzed geochemically for the purpose of assessing their fossil energy resource potential. Organic geochemical data have been obtained for a better definition of the oil and gas contained in the Devonian shales.

The hydrocarbon source potential of fine-grained sediments from various worldwide locations has been studied by many researchers (Bailey et al., and Welte, 1972). The hydrocarbon source rock studies were performed to investigate the organic richness, type (gas, condensate, or oil), and state of thermal maturity of the hydrocarbon source rocks, and to determine their areal and stratigraphic distribution. Specific geochemical zones (organic facies) are also delineated.

The location of the four wells is displayed in Figure 1. In most cases, the entire stratigraphic unit of Devonian shale was cored. Samples for geochemical analyses were taken at 30-foot intervals and stored in air-tight metal containers. Shortly after arrival at the laboratory, the container's air space was sampled for methane to heptane hydrocarbons. The container was opened and additional geochemical analyses were performed.

TECHNIQUES

The geochemical analyses performed on the Devonian shale samples are shown in Figure 2. The abundance of methane through heptane hydrocarbons (C_1-C_7) was measured by summing the contents of the air space and core material stored in an air-tight container. Organic carbon was analyzed by combustion of the carbonate-free sediment. The kerogen was examined visually for morphological classification after being isolated from the inorganic matrix. Dried core material was crushed and extracted with a benzene-methanol solvent. The soluble extract was weighed, then separated into fractions by adsorption and liquid chromatography. The normal paraffin distribution was determined by gas chromatography. Vitrinite reflectance was measured using modifications of procedures described by Landes (1967), and Hacquebard and Donaldson (1970).

DISCUSSION AND RESULTS

A. Organic Facies

Organic Carbon

The organic carbon content of fine-grained argillaceous sediments such as the Devonian shales is an indicator of organic richness. Organic matter comprised mostly of organic detritus is preserved by rapid burial. Alteration processes such as microbial degradation and thermal diagenesis transform the organic matter to the complex heterogeneous material called "kerogen". Kerogen is presumed to be the major precursor for oil and gas. As the sediments become thermally matured, oil and gas are generated. The amount of kerogen, expressed as the organic carbon content, shows the abundance of organic matter which may be altered to form hydrocarbons. The lower limit of organic carbon in shales from productive basins is 0.4 percent (Ronov, 1958). The worldwide average of organic carbon in shales and siltstones is 1.14 percent (Gehman, 1962).

The amount of organic carbon in Devonian shales varies from location to location (Fig. 3). In general, the average organic carbon content of sediments from the I-1, 0-1, KY-2, and R109 wells is 6.77%, 8.75%, 2.04%, and 1.36% respectively. The organic matter appears to be more uniformly distributed in the I-1 and 0-1 wells. However, to the east, the KY-2 and R-109 shales vary considerably in organic carbon from a low of 0.16% to a high of 7.75%.

Type of Organic Matter

The solid organic matter contained in fine-grained sediments visually reflects its source of deposition. Composed mostly of organic detritus, the kerogen is related to its depositional environment by the proportions of marine and continental organic matter it contains. Kerogen identified visually can be classified as amorphous, herbaceous, woody, or coaly (inertinite). After maturation by thermal diagenesis, the marine (amorphous) type is prone to generate abundant gaseous and liquid hydrocarbons. The nonmarine (woody-coaly) type is prone to produce mostly gaseous hydrocarbons (Staplin, 1969 and Tissot et al., 1974).

Of the four wells studied, the type of organic matter in the I-1 and 0-1 wells is primarily herbaceous and amorphous kerogen (Fig 4). This lipid rich material (if present in sufficient quantities) has the potential to generate abundant oil and associated gas. In contrast, shales from the KY-2 and R-109 wells contain predominant amounts of either the herbaceous-amorphous kerogen or the woody-coaly (gas prone) kerogen. The high organic carbon content appears to be associated with the kerogen type. In most cases, the herbaceous-amorphous kerogen is present in shales which contain abundant organic carbon. The shales containing primary or secondary amounts of woody-coaly kerogen are lean in organic matter. For example, within the stratigraphic sequence represented by core material in the KY-2 well from 2440± feet to 2550± feet, the changes in kerogen type from herbaceous-amorphous to woody-coaly and in organic carbon content from 7.75% to 0.16%, probably represent a change in depositional environment. The environmental shift from marine to nonmarine kerogen types may be the result of a regressive depositional cycle.

C_{15}+ Extract

Core material was extracted with organic solvent to yield the C_{15}+ extract or "bitumen". The bitumen is composed of hydrocarbon and nonhydrocarbon material. The bitumen in recent sediments is impoverished in hydrocarbons and contains mostly nonhydrocarbon material. As the sediments become thermally matured, increasing amounts of hydrocarbons are formed. The average worldwide concentration of hydrocarbons in shales was found to be 96 ppm (Gehman, 1962).

Shales from the four wells were found to contain bitumen composed mostly of hydrocarbons. The distribution of hydrocarbon and nonhydrocarbon material extracted from the Devonian shales is shown in Figure 5. The hydrocarbon portion consists of paraffin-naphthene (P-N) and aromatic (AROM) fractions. The nonhydrocarbon material is separated into asphaltene (ASPH) and nitrogen-sulfur-oxygen containing compounds (NSO's). In the I-1 and 0-1 wells, the average hydrocarbon content was 2159 ppm and 2463 ppm, respectively. The average hydrocarbon content was 1469 ppm in KY-2 shales, and 1245 ppm in R-109 shales. The hydrocarbon content appears to be related to the organic carbon content and the kerogen type. In general, shales characterized by herbaceous-amorphous kerogen, and a high organic carbon content contain abundant C_{15}+ hydrocarbons. These shales are represented in Figure 2 through

6 as organic facies A. Sediments with low organic carbon content and primary or secondary amounts of woody-coaly kerogen and low amounts of $C_{15}+$ hydrocarbons are designated as organic facies B. Based on the geochemical data, there appears to be a transitional zone where mixtures of organic facies A and B are present.

The geochemical zonation assigned to the shale intervals was based on their ability to satisfy the following conditions:

Organic Facies A

Organic Carbon Content: $>1.0\%$
$C_{15}+$ Hydrocarbon Content: >1000 ppm
Kerogen Type: Primary or Secondary Amounts of Herbaceous or Amorphous Kerogen

Organic Facies B

Organic Carbon Content: $<1.0\%$
$C_{15}+$ Hydrocarbon Content: <1000 ppm
Kerogen Type: Primary or Secondary Amounts of Herbaceous-Amorphous or Woody-Coaly Kerogen

Shales which did not satisfy these requirements were thought to represent a transitional zone.

Abundance of C_1-C_7 Hydrocarbons

Gas and gasoline-range hydrocarbons are generated from organic matter at different levels of thermal maturity. Initially, at low temperature, microbial degradation forms methane or "dry" gas. With increasing time, temperature, and depth of burial, heavier hydrocarbons are generated. In the early stages of petroleum formation, gas-oil range hydrocarbons predominate with associated amounts of "wet" gas (C_2-C_4 hydrocarbons) and gasoline-range hydrocarbons. The content and distribution of C_1-C_7 hydrocarbons is primarily dependent on three geochemical parameters; namely, the organic richness, the type of organic matter, and its level of thermal maturity.

Shales from each well contained large quantities of C_1-C_7 hydrocarbons (Fig. 6). The average C_1-C_7 abundance in the I-1, 0-1, KY-2, and R-109 wells was 440,000 ppm, 313,000 ppm, 356,000 ppm, and 763,000 ppm, respectively. (The concentration is expressed as volumes of gas per million volumes of core material.) In the I-1, 0-1, and R-109 wells, the dry gas, wet gas, and gasoline-range hydrocarbons were uniformly distributed. However, in the KY-2 well, organic facies B characterized by lean organic carbon content contained significantly lower amounts of C_1-C_7 hydrocarbons.

B. Thermal History

In order to assess the hydrocarbon generating capacity of potential source rocks, the thermal history and its diagenetic effect on petroleum generation must be evaluated. Two methods, kerogen coloration and vitrinite reflectance, were used to measure the thermal alteration of the Devonian shales. The kerogen coloration of the plant cuticle and spore-pollen debris is measured in transmitted light. The state of thermal alteration (Thermal Alteration Index or TAI) ranges from light greenish yellow at Stage 1 for unaltered kerogen to black at Stage 5 for severely altered kerogen. The thermal zone of oil generation corresponds to a moderately mature to mature kerogen of Stage 2 to 3- (Fig. 7). The kerogen in the zone of oil generation is characterized by yellow-orange to light brown color. Vitrinite reflectance (R_o) is also used to measure the degree of thermal alteration. R_o values ranging from 0.2 to 0.6 indicate that the sediments are too immature for oil generation. The zone of petroleum generation is usually interpreted to range from 0.6 to 1.2. R_o values from 1.2 to 3.0 indicate a thermal history sufficient to form wet gas and methane. The severely altered or metamorphosed organic matter represented by R_o values greater than 3.0 is considered as nonsource for hydrocarbons.

The thermal history of the Devonian shales analyzed in this study exhibit a small amount of variation (Fig. 8). The organic matter in shales from the four wells is characterized by its yellow to orange brown color. This coloration is consistent with a thermal alteration index of Stage 1+ to 2+. The average value of Stage 2 corresponds to a thermal history equal to the early stages of petroleum generation. The mean average vitrinite reflectance value in both the I-1 and 0-1 wells is 0.45. In the KY-2 well, a slightly higher thermal alteration corresponding to a mean average R_o of 0.52 was measured. The mean average R_o for vitrinite particles in the R-109 well was 0.70. Based on the vitrinite reflectance data, it appears likely that the Devonian shales will be increasingly more mature in an east-south-easterly direction.

CONCLUSIONS

The Devonian shales are evaluated as a potential source of oil and gas based upon the type of kerogen present, its degree of thermal alteration, and the nature of hydrocarbons which it has generated. A preliminary evaluation of the geochemical data obtained from core material seems to indicate the following regional trend in an east-south-easterly direction:

Organic richness

0-1 > I-1 >> KY-2 > R-109

Abundance of oil prone organic matter

0-1 $\cong$ I-1 >> KY-2 $\geq$ R-109

Liquid Hydrocarbon Abundance

0-1 > I-1 >> KY-2 > R-109

The stratigraphic interval penetrated by the four wells contains two distinct zones or organic facies, based on the organic carbon content, the abundance of $C_{15}+$

extract, and the organic matter type. Organic facies A are classified as rich oil prone hydrocarbon sources. Organic facies B are interpreted to be predominately gas sources. In some shales, organic matter consisting of both facies A and B constitute a transitional zone.

The degree of thermal alteration has been sufficient to initiate the hydrocarbon forming process in Devonian shales in all four wells. Shales from the I-1 and 0-1 wells are at the same level of maturation. KY-2 and R-109 shale are slightly more mature.

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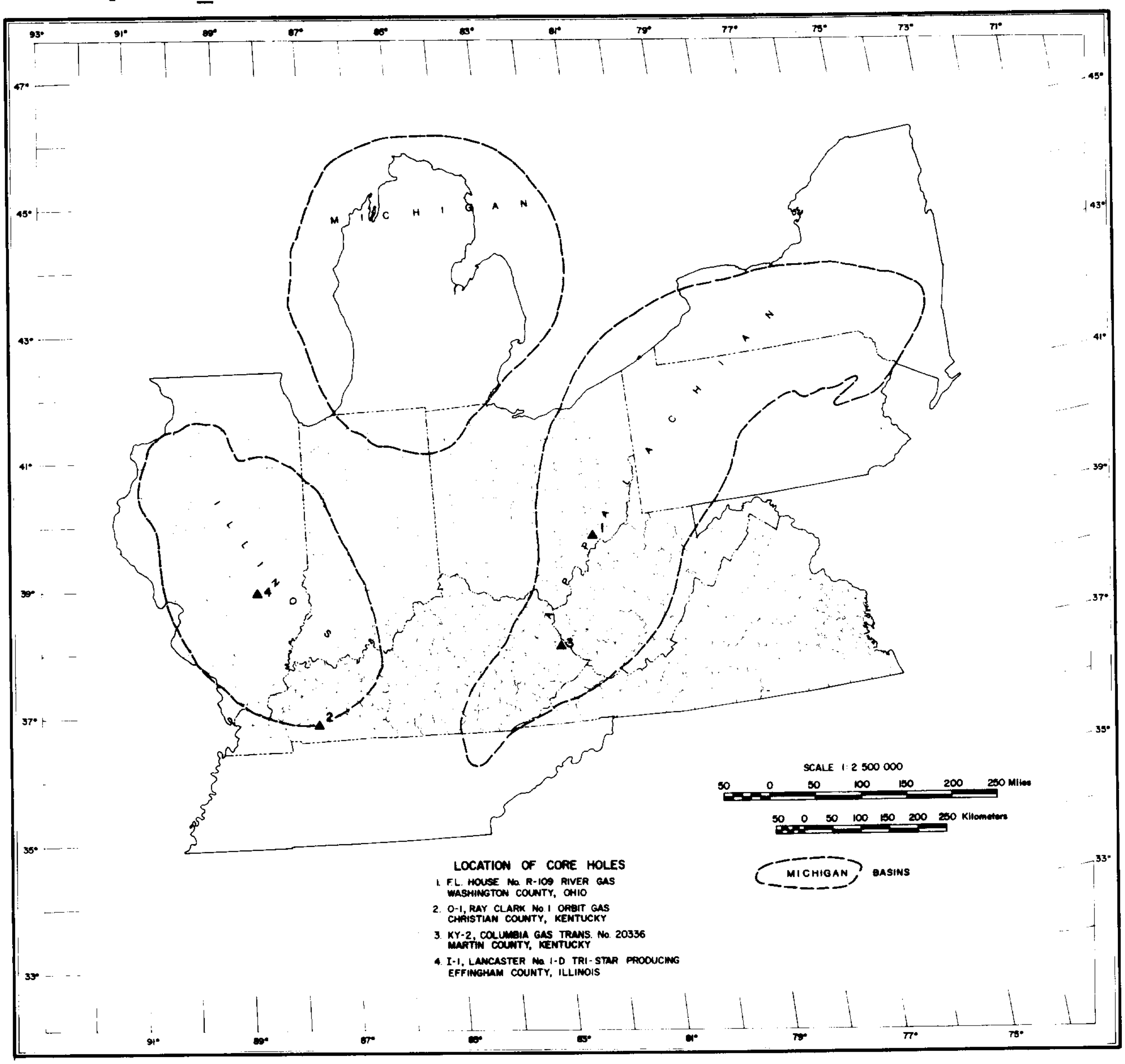

Fig. 1

Location of core holes

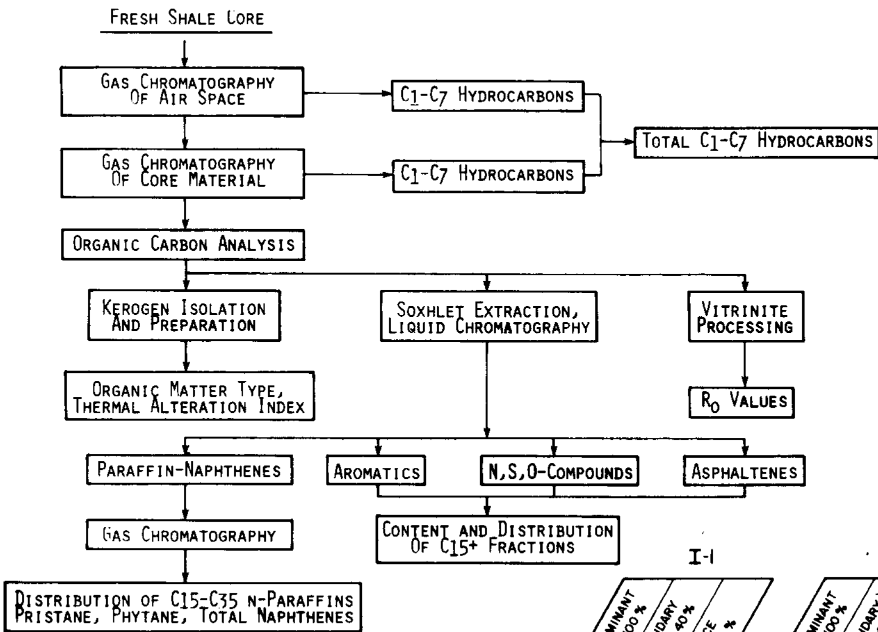

Fig. 2
Organic geochemical analyses

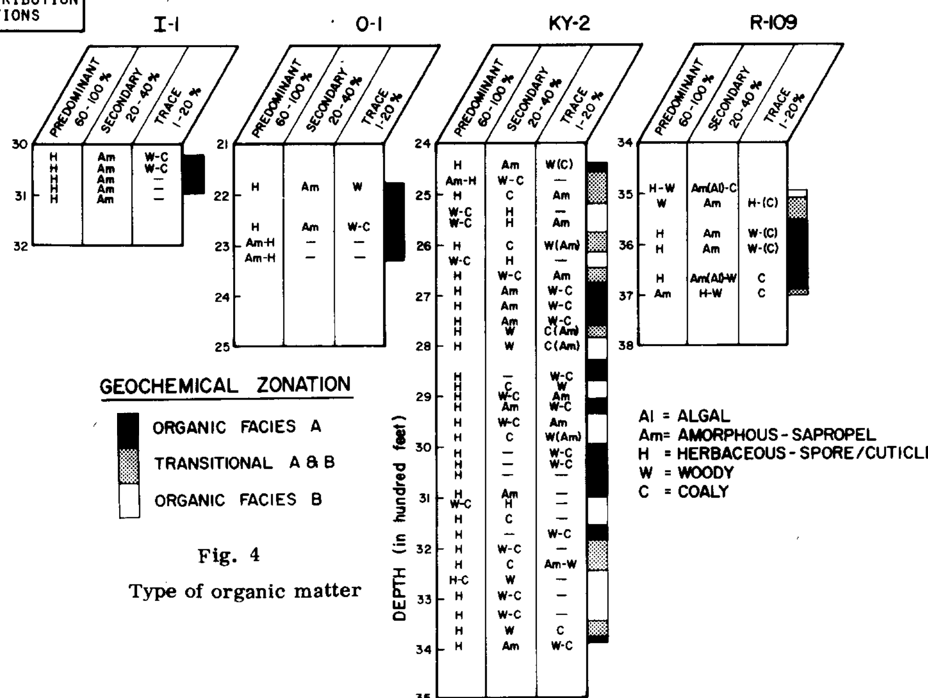

Fig. 4
Type of organic matter

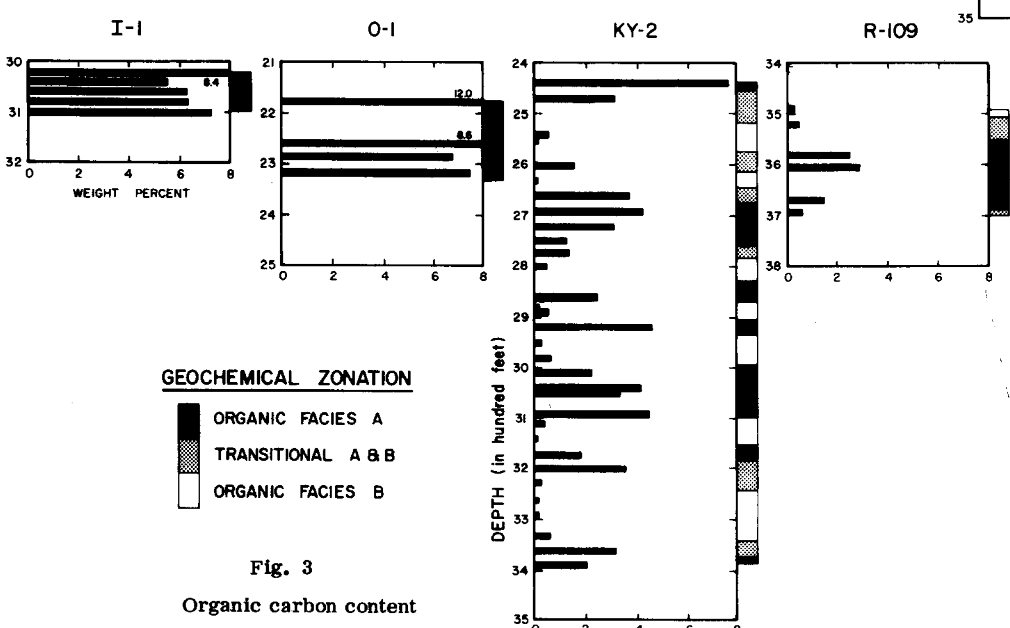

Fig. 3
Organic carbon content

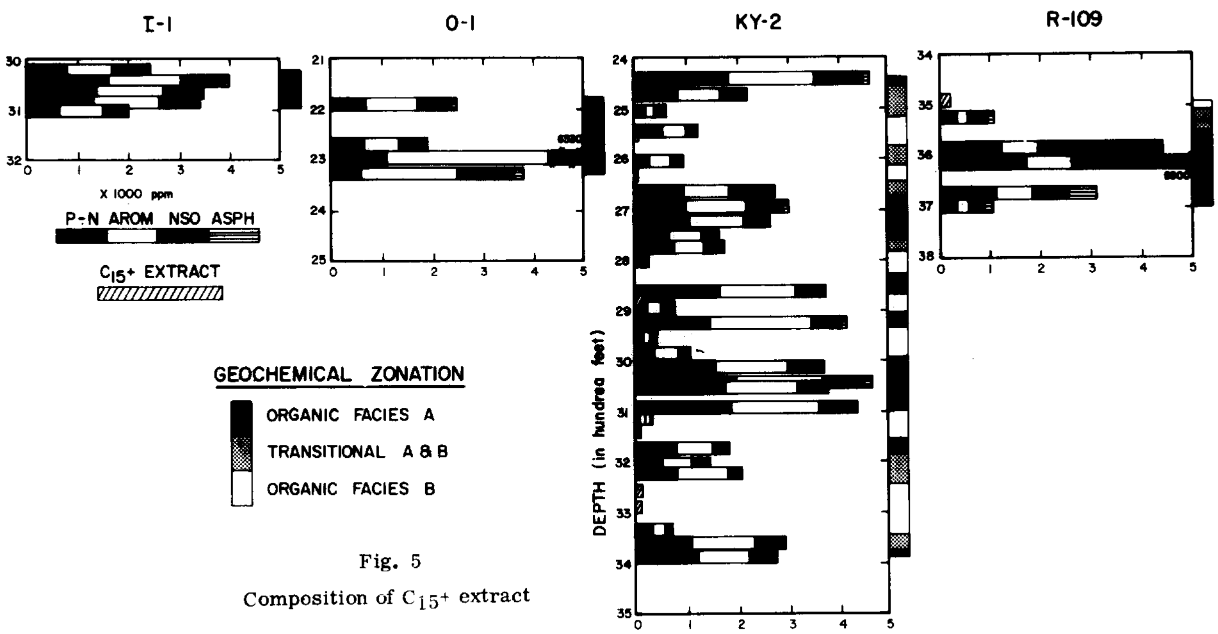

Fig. 5

Composition of C_{15}+ extract

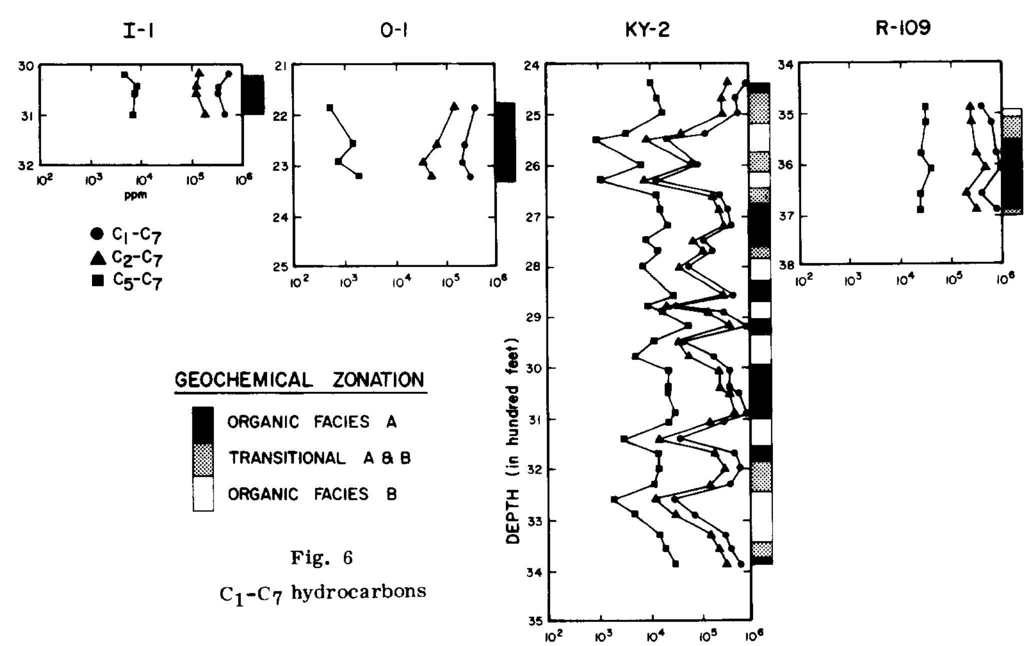

Fig. 6

C_1-C_7 hydrocarbons

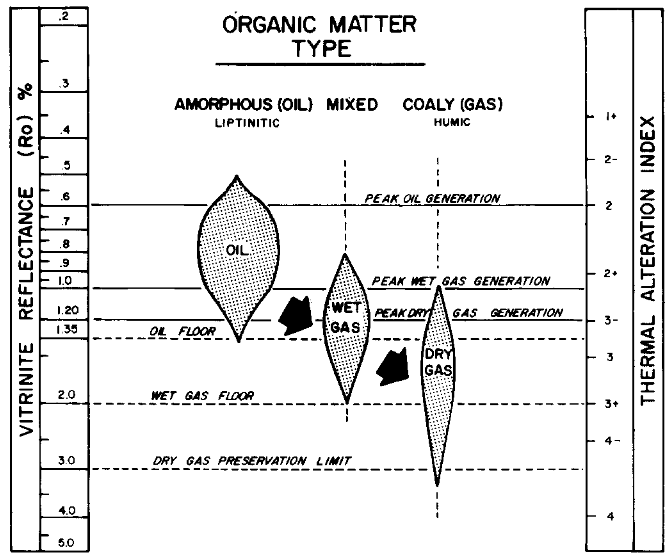

Fig. 7
Zones of hydrocarbon generation

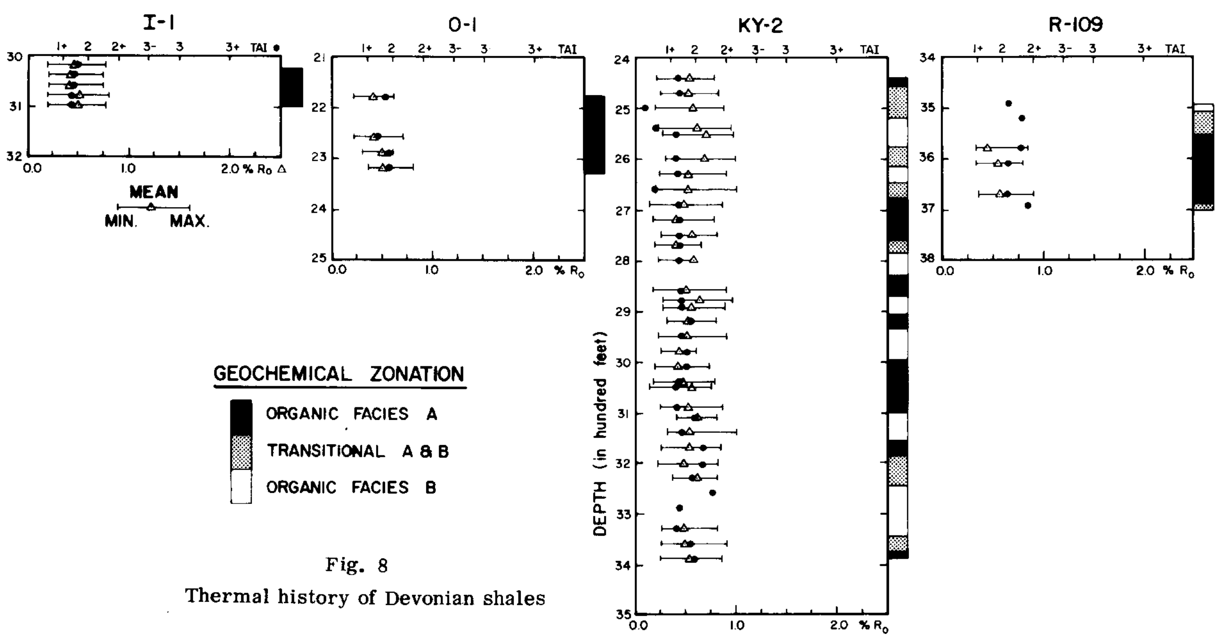

Fig. 8
Thermal history of Devonian shales

THE GENERAL ELECTRIC COMPANY
ELECTRODRIL FIELD TEST DEMONSTRATION PROGRAM

by

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ABSTRACT

The development of a downhole electric drilling system, begun in 1973, was brought to culmination in the second half of 1976. During this time, a demonstration program was run under a joint program sponsored by ERDA, General Electric, and other industry participants. During the demonstration program, The Electrodril Directional and Deep Drilling Systems were demonstrated.

The Directional System is made up of a 60 HP motor subsystem, a downhole instrument subsystem, a cabling subsystem, and the surface control and display subsystem which ties the sub elements into a system. The instrument subsystem includes the directional sensors package which provides the data utilized to kick off and control deviated drilling.

The Deep Drilling System is very similar to the Directional System except that a 285 HP motor is used and the cabling deployment method differs slightly in order to accommodate the need to rotate the drill string to obviate differential sticking.

Since the new year, and again under ERDA joint participation, the cabling subsystem was modified to accommodate the need for field replaceable connectors. In addition, seal modifications were made to the motor subsystem to extend its operational life.

The paper will describe the system elements of both drilling systems (generically called ELECTRODRIL) and detail the test accomplishments derived from both the 1976 and early 1977 test programs.

Prepared for the Energy Research and Development Administration, under Contract No. EY-76-C-02-4033.A002.

Note: Copies of this paper are available from the author.

DRILLING RATE CHANGES WHEN AIR DRILLING IS SWITCHED TO MIST DRILLING

BY

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ABSTRACT

Eight shallow (30-foot-deep) holes were drilled in four formations to determine if a significant portion of the reduction in penetration rate that usually occurs when air drilling is changed to mist drilling (air driller's rule-of-thumb estimates average about one-third loss) might be due to the physical action of drilling a wet, soapy rock. The results showed an average loss of 9.3 percent in the four formations drilled, with the greatest loss occurring in limestone. The softest formation (claystone) showed only a 1.2- percent reduction in penetration rate; the two sandstones averaged 10.0- percent loss; and the limestone showed a significant 15.8-percent loss. This indicates that the loss of penetration rate due to wetting the rock while mist drilling is small but would be significant when drilling a long interval.

The findings indicate that when drilling hard rocks at the surface with mist instead of air, a penetration rate loss of approximately 12 percent (compared to the drilling rate with air) will occur due to the effect of jetting the soapy water through the bit onto the formation being drilled. A further investigation is required to determine if the same effect occurs while drilling at depth under varying hydrostatic heads and to determine if the effect can be eliminated to provide increased drilling rates.

INTRODUCTION

The drilling industry uses air drilling when economically feasible because faster penetration rates are usually obtained when air is used as the circulating medium instead of drilling mud. Unfortunately, certain problems associated with air drilling limit its use to only a few areas in the United States. This report describes one of the phenomena affecting drilling rates while attempting to drill with air as the circulating medium.

When water is encountered during air drilling, the usual procedure is to attempt to convert to mist drilling. Mist drilling is performed by pumping small

1/ Petroleum engineer

volumes of a concentrated soap and water mixture into the air stream at the surface. The total mixture flows down the drill pipe, through the bit nozzles, and into the annulus where the resulting soap bubbles reduce the density of the produced water thereby allowing the air to lift the water and drill cuttings to the surface. If the quantity of produced water is not too great, and problems such as water-sensitive (swelling) clays or sloughing shale do not occur due to water wetting, then mist drilling can be continued until additional water is encountered or other problems occur.

In past drilling operations, a significant decrease in penetration rate has been observed when switching from air to mist drilling. Some drillers use a rule-of-thumb that predicts a one-third decrease in penetration rate when making this change. Actually, as much as 50- to 75- percent decrease has been observed when light drilling weight was being used to control deviation and prevent a crooked hole. These observations, and a desire to reduce the penetration rate losses, prompted this field experiment.

Underbalanced drilling--that is, hydrostatic pressure less than in situ pressure--provides faster drilling rates than overbalanced drilling and, since air drilling is the ultimate in underbalanced drilling, it follows that this is the main reason for higher penetration rates while drilling with air. Converting from air drilling to mist drilling is usually done because water has been encountered; therefore, the pressure head on the formation changes from a column of air to a column of aerated soapy water. This increase in hydrostatic head is generally considered to be the major reason for the decreased drilling rate that occurs when changing from air to mist, but the drilling rate might also be adversly affected by the physical action of drilling a rock that is continously being wetted with a soapy spray through the bit.

It was conceivable that if the soapy water used for mist drilling could be injected into the annulus immediately above the drill bit then the bit would still be drilling a dry rock and a penetration rate increase might be realized. This could be accomplished with concentric drill pipe or a downhole separator with a ported sub above the bit. Before the acutal purchase and construction of experimental equipment, some evidence was needed to prove whether the soapy water spraying through a drill bit acutally does affect the drilling rate of various rocks. Methods to determine the amount of this effect were considered, and these field experiments were conceived and performed to determine that effect.

Since changes in hydrostatic head cause a dramatic effect on penetration rates, the effect of the wetting action on the rock could only be evaluated by drilling rocks at the surface where the hydrostatic head should be negligible. The experiment was performed in the field by locating outcroppings of suitable rocks, drilling one 30-foot hole with air, and then moving about 5 feet and drilling a second hole with mist. Acceptable data were obtained by holding all other drilling variables constant.

FIELD TESTS

Location

A contractor with a small hydraulic-controlled drilling rig was located in Phoenix, Arizona, and only minor equipment modifications were necessary to provide good control of other drilling variables. The location of the contractor and equipment influenced the selection of an area of rock outcrops in northeast Arizona as the work site. The four outcrops selected were the Coconino Sandstone, a claystone, the Moenkopi Sandstone, and the Kaibab Limestone. The drilling was performed on Arizona State highway rights-of-way where road cuts allowed a visual inspection of the rocks to be drilled.

Cores for rock characterization were taken midway between the holes at three of the locations. No core was taken in the claystone because it was unlikely that good core data could be obtained owing to the soft, stratified nature of the formation. The core analysis data showing rock characteristics are presented in table 1; however, water saturation measurements were not taken because one of the requirements for drill site selection was that the site be more than 30 feet above the local water table. All of the air holes "dusted" throughout the drilled interval, and no free water was observed.

Rig Equipment and Controls

The small, mobile, hydraulic rig provided a visual pointer against a footage tape which allowed accurate incremental measurement and timing. The weight on the bit was accurately held constant by a hydraulic "pulldown" system which was calibrated before the experiment. A calibrated tachometer was used to indicate rotary speed, but the sensitivity of this control was low, and this measurement was verified by hand timing at regular intervals. The rig also had a 60-gallon pressure tank which allowed control of the volume of mist by using differential pressure to force the soapy water through a calibrated needle valve. A power swivel provided a smooth, steady source of torque for drilling. A portable air compressor was always operated at the same throttle and pressure settings. The equipment provided good control of the drilling variables, but in those instances where possible discrepancies existed, the data obtained have been deleted from the comparison. All of the holes were drilled with 4 3/4-inch, hard-formation, milled tooth bits with an air volume of approximately 360 Mcfd. In order to reduce bit dullness as a factor in the drilling rate comparisons, four new bits were used in the four holes drilled in the Conconino and Moenkopi. These bits were undamaged and were used in the other four holes.

Coconino Sandstone Test

The first drill site was an outcrop of Coconino Sandstone about 5 miles southeast of Holbrook, Arizona. The weight on bit was 8,000 lb, and rotary speed was 48 rpm. The intervals from 9 to 16 and 19 to 28 feet were drilled in 61.5 minutes using air and 69 minutes using mist. This shows that the mist drilling was 12.2 percent slower than the air drilling. Drilling time for the 3-foot interval from 16 to 19 feet was deleted as not representative because of mechanical problems on the mist hole. The average rock characteristics of four test points from the Coconino Sandstone core are porosity, 18.3 percent; permeability, 391 md; and compressive strength, 5000 psi. The cored section showed a fairly uniform homogeneous sandstone.

Figure 1 shows the drilling rate curves obtained. All of the drilling curves have been plotted using a running average to reduce the significance of minor discrepancies in measurements of depth or timing. This was the first hole drilled, and the ragged appearance of the early portion of the curves is probably an indication of crew training on parameter control. In retrospect, this location probably should have been redrilled to obtain more uniform curves similar to the latter portion of the curves.

Claystone Test

The second location was drilled in a claystone in an attempt to simulate drilling a competent shale. The rotary speed was 56 rpm, and the bit weight was 4,000 lb from 8 feet to 23 feet and then was increased to 6,000 lb. When wetted by the mist, this formation became sticky and soft, but it drilled satisfactorily with both the mist and the air.

The overall time for drilling 21 feet from 8 to 30 feet (1 foot deleted) was 41 1/2 minutes with air and 42 minutes with mist for a decrease in penetration rate of only 1.2 percent. Since a larger decrease had been expected, this result was surprising. This information would indicate that mist drilling could be utilized for dust control in soft-formation, surface-hole drilling, such as mining operations, without a significant loss of penetration rate. No core samples were taken in the claystone owing to the incompetent stratified nature of the formation. Figure 2 shows the drilling rates obtained in the claystones.

No outcrops of competent shale were available near the work area, and the claystone was selected to simulate drilling in shale; however, the selection may have been a poor choice since the drilling results do not substantiate previous oilfield experience while drilling shale with air and mist.

Moenkopi Sandstone Test

Location No. 3 was a Moenkopi sandstone which was drilled with a bit weight of 10,000 lb and a rotary speed of 56 rpm. The total drilling time from 10 to 31 feet was 40 and 54 minutes with air and mist, respectively, resulting in a 35-percent decrease in penetration rate while mist drilling. These data fell more in line with what had been expected when the experiment was begun; however, portions of the data appeared questionable and the apprehension became justified when a subsequent core from 10 to 20 feet recovered a near vertical fracture or joint. When the direction and dip of surface jointing, visible from a nearby road cut, were considered, it was evident that the lower part of the air-drilled hole had encountered this fracture. Analysis of the footage data substantiate this conclusion because the penetration rate nearly doubled below 20 feet in the air hole, but was nearly constant in the mist hole. Drilling time from 10 to 20 feet was 25.5 and 27.5 minutes with air and mist, respectively, but was 14.5 and 26.5 minutes, respectively, from 20 to 30 feet. Considering only the data from 10 to 20 feet as reliable, the decrease in penetration rate was 7.8 percent owing to mist drilling.

The Moenkopi core data show a uniform sandstone matrix (except for the fracture which was partly filled with crystals) with average characteristics of 8.9 percent porosity, 5.5 md permeability and 6,900 psi compressive strength. Figure 3 shows the drilling rate curves from 10 to 20 feet.

Kaibab Limestone Test

The fourth and last drill site was in the Kaibab Limestone about 15 miles south of Winslow, Arizona. The holes were drilled with 10,000 lb of bit weight at 56 rpm. For the 16-foot interval from 4 to 20 feet, the drilling time was 28.5 minutes with air and 33.0 minutes with mist. This reflects a 15.8 percent reduction in drilling rate due to the injection of soapy water.

A 10-foot core taken from 8 to 18 feet showed that the drilled section was not a homogeneous formation. It graded from a vugular limestone at the top to a sandy lime in the middle and a limy sand at the bottom. As a result the average rock characteristics are of minor significance. The porosity ranged from 13.8 to 21.5 percent for an average of 18.5 percent. Permeability ranged from 2.3 md. to 90.6 md, and the average of six sample points was 46.8 md. Compressive strength was 8,800 psi in the limestone, but dropped to 2,900 psi in the limy sand at the bottom of the core. The data are presented in table 1. The drilling rate curves are shown in figure 4. Drilling rate data for all four locations are presented in table 2.

CONCLUSIONS

Evaluation of this experimental field data has led to the following conclusions regarding penetration rate changes when air drilling is converted to mist drilling.

1. This work confirms the previous speculations that the addition of soapy water causes a loss of penetration rate when air drilling is changed to mist drilling at shallow depths.

2. The penetration rate loss due to the physical action of the soapy water spraying through the bit is of low magnitude, and for shallow, hard surface formations it is probably in the range of 12 percent compared to air drilling rates.

3. Further investigation is probably justified toward development of a downhole liquid separator with a ported sub which would inject the soapy water above the bit while mist drilling.

4. Mist could be used for dust control in shallow, soft-surface drilling with only a small loss of penetration rate.

ACKNOWLEDGMENTS

We wish to thank the Arizona Department of Transportation, Highways Division, for permission to conduct the drilling experiments within the State right-of way. This concession saved much time and prevented unnecessary expense. We also thank Engineers Testing Laboratories, Inc. for the excellent personnel and equipment which they provided.

TABLE 1. - Core analysis data: air-mist penetration rate experiment

Formation	Depth, feet	Porosity, percent	Permeability, millidarcies	Compressive strength lb/in^2	Remarks
Caconino Sanstone.	8.6	18.9	306	4,800	Appeared homogeneous.
	10.1	17.9	290	4,300	
	11.6	18.2	399	5,400	
	13.4	18.2	568	5,400	
Average		18.3	391	4,975	
Moenkopi Sandstone.	13.8	9.7	3.6	8,800	Uniform matrix with occasional wafer thin bedding.
	15.2	8.2	4.6	7,200	
	16.9	8.2	9.5	6,800	
	18.3	8.7	3.5	6,300	
	19.8	9.8	6.5	5,400	
Average		8.9	5.5	6,900	
Kaibab Limestone.	8.1	14.4	3.5	8,800	Limestone.
	9.5	13.8	2.3	8,800	Do.
	11.7	20.1	48.2	5,400	Sandy lime.
	13.3	21.3	64.6	5,900	Do.
	15.8	20.0	71.4	3,200	Limy sand.
	17.8	21.5	90.6	2,900	Do.
Average		18.5	46.8	5,800	

TABLE 2. - Drilling data tabulation: air-mist penetration rate experiment

Formation	Overall depth interval, feet	Length of compared interval, feet	Air drilling time, minutes	Mist drilling time, minutes	Change compared with air, percent	Penetration rate, ft/hr	
						Air	Mist
Coconino Sandstone...	9-28	[1] 16	61.5	69.0	-12.2	15.6	13.91
Claystone...	8-30	[2] 21	41.5	42.0	- 1.2	30.4	30.0
Moenkopi Sandstone...	10-20	10	25.5	27.5	- 7.8	23.5	21.8
Kaibab Limestone...	4-20	16	28.5	33.0	-15.8	33.7	29.1
Average change					- 9.3		

[1] 3 ft deleted, parameter control inaccurate.
[2] 1 ft deleted, parameter control inaccurate.

Note 1. Negative sign indicates that mist drilling was slower than air drilling.
Note 2. Individual footage data were taken during the experiment but are not presented because an error of a few seconds or inches in depth on a per-foot measurement exceeds the magnitude of the percent change in drilling rate but has little effect on the data for the overall interval.

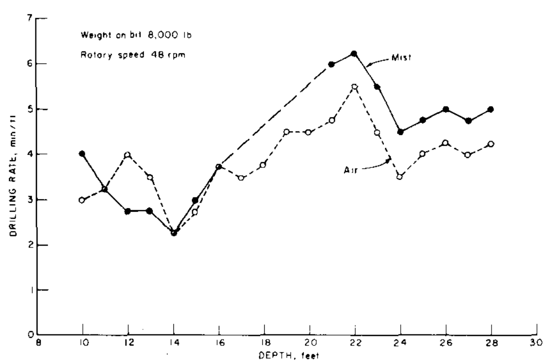

FIGURE 1 - Drilling Rate vs Depth, Coconino Sandstone.

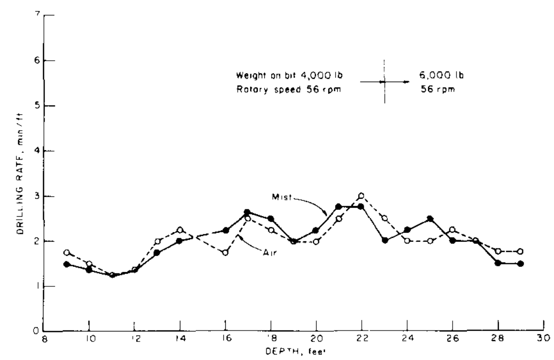

FIGURE 2 - Drilling Rate vs. Depth, Claystone

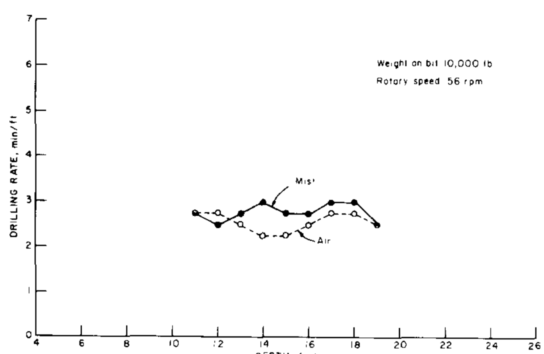

FIGURE 3 - Drilling Rate vs. Depth, Moenkopi Sandstone.

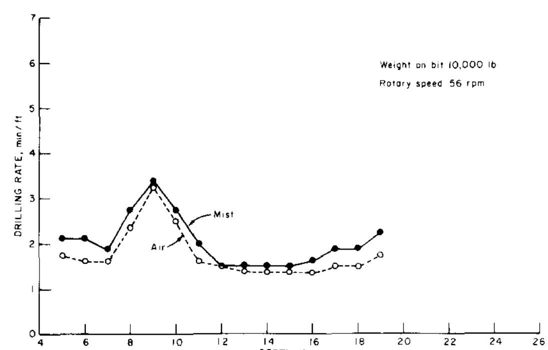

FIGURE 4.- Drilling Rate vs. Depth, Kaibab Limestone.

FULL-SCALE LABORATORY DRILLING UNDER SIMULATED DOWNHOLE CONDITIONS

by

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ABSTRACT

Full-scale drilling experiments have been performed using a 7 7/8-inch rotary insert bit simulating downhole deep-well conditions. Tests were conducted using bit weights to 40,000 pounds, rotary speed to 100 RPM, mud flows to 220 GPM, mud pressure to 5,000 psi, and confining pressure on the rock to about 9,000 psi. Several rock types have been drilled; data presented here include tests on Colton Sandstone and Bonne Terre Dolomite. Penetration rates from about 3 to 90-feet per hour were obtained. Penetration rates were strongly dependent on bit weight, rotary speed, and borehole mud pressure. There was only a small dependence on mud flow rates. Visual examination of the drilling patterns at simulated downhole conditions suggested ductile behavior for the sandstone, but more chipping and cratering suggested more brittle behavior for the Dolomite.

INTRODUCTION

Laboratory tests have been conducted over the past two or three decades to study the effects of deep-well conditions on drilling bit performance. These tests have included single tooth penetration experiments,[1,2], microbit drilling[3], drilling with small standard three-cone bits in impermeable rock[4], and large standard three-cone bit drilling in permeable and impermeable rock[5].

Such tests have studied the effects of bit weight and RPM on penetration rate versus simulated depth; rotary power requirements versus depth; the effect of "chip hold-down" and over-balanced drilling conditions; threshold pressures necessary to form craters at simulated depth; and effects of bit cleaning and jet drilling.

In general, the single tooth penetration, single cutter rotation and microbit drilling tests dramatically demonstrated the effects of reduced rock volume removal and penetration rate at simulated depths and the need for better bit hydraulics. However, the results were basically qualitative and, in most cases, difficult to interpret and extrapolate to full-scale bit performance in the field.

Prepared for the Energy Research and Development Administration, under Contract No. E(34-1)-0038.[6]

In 1974, a new laboratory test facility, the Drilling Research Laboratory, Salt Lake City, was designed to test full-scale drill bits at much greater simulated depths than previously performed. This paper summarizes the results of full-scale laboratory drilling performed at the Drilling Research Laboratory. Tests were conducted with standard 7 7/8-inch rotary insert bits in two types of rock typically found in deep oil and gas reservoirs in the United States at deep hole drilling conditions where rock plasticity and hydraulic hold-down of cuttings impede chip removal.

The object of the work was to determine the effects of changing various drilling parameters on the drilling rate while drilling at simulated depths.

ROCK, DRILL BIT AND DRILLING FLUID SELECTION

The two rock types used for the tests were Colton Sandstone and Bonne Terre Dolomite. The mechanical and physical properties of the rock samples were determined in the Rock Mechanics Laboratory at Terra Tek. Table 1 summarizes the mechanical and physical properties for the Sandstone and Dolomite. Triaxial compression tests were also run with the failure envelopes shown in Figure 1. The permeability of both the Sandstone and Dolomite were so low it was found impractical to control the pore pressure during the drilling tests.

Drilling was performed with standard 7 7/8-inch rotary insert bits. The drill bits selected were recommended and donated by the manufacturers indicated.

MANUFACTURER	BIT TYPE	ROCK TYPE
Smith Tool	F3	Colton Sandstone
Security/Dresser	M89TF	Bonne Terre Dolomite

The drilling fluid was a standard water base mud with properties outlined in Table 2.

TEST CONDITIONS

Each rock type was drilled at atmospheric conditions and simulated depths to 10,000 feet. Drilling parameters were varied as follows:

Weight on Bit	5,000-40,000 pounds
Rotary Speed	40-100 RPM
Mud Flow	80-220 GPM
Borehole Mud Pressure	100-5,000 psi
Confining Pressure on Rock	0-9,000 psi

Penetration rates from about 3-feet per hour to about 90-feet per hour were obtained.

The tests were performed with the Drilling Research Laboratory equipment and facilities. A detailed description of the test facility is given in Appendix A. Rock specimens drilled under simulated downhole conditions were 13 ½-inch diameter by 3-foot long cylinders sealed from the confining fluid with a urethane jacket and steel end caps prior to placement in the pressure vessel.

RESULTS OF THE EXPERIMENT

For the Colton Sandstone experiment, typical results of penetration rate as functions of rotary speed, weight on bit and borehole mud pressure are shown in Figures 2 and 3.

The borehole mud pressure was particularly significant in controlling the drilling rate. As the mud pressure was raised, the drilling rate dropped rapidly until the pressure reached about 2,000 psi. At borehole mud pressure above this value, the increased pressure had a small effect. Evidently, the chip hold-down and imperfect cleaning effects resulting from the differential between the mud and pore pressures tended to reach a critical level. Once this critical level was reached, the drilling rate was then dependent primarily on bit weight.

For the Bonne Terre Dolomite, typical results of penetration rate as functions of rotary speed, weight on bit and borehole mud pressure are shown in Figures 4 and 5. From these curves, it is also seen that the qualitative results of the Dolomite drilling are similar to the Sandstone drilling. The effect of the borehole mud pressure is less in the Dolomite than in the Sandstone, however.

Tabulated data for both the Colton Sandstone and Bonne Terre Dolomite are presented in Appendix B.

Upon examination of the bottom hole pattern of the rock after drilling at high pressures, it was visually apparent that the Sandstone had been in a highly ductile state (as if the bit was drilling putty) whereas the Dolomite left evidences of chipping and cratering.

CONCLUSIONS

With the rock types, bit types and drilling conditions studied, the drilling penetration rate was found to be primarily dependent on the rotary speed, weight on the bit and borehole fluid pressure. There was a small dependency on mud flow rate and an apparent negligible effect from the confining stress on the rock. The dependence on the mud pressure was particularly significant since the penetration rate decreased rapidly until the differential mud pressure reached approximately 2,000 psi. Above this value, additional mud pressure and rotary speed had only a minor effect on penetration rate. The effect was more pronounced in the Sandstone than the Dolomite. Visual examination of the rock bottom hole pattern after drilling at simulated downhole conditions revealed much ductility in the Sandstone and more chipping and cratering in the Dolomite.

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APPENDIX A

The main areas and components of the laboratory, shown in Figure A1, are the rig room, drill rig, drilling pit with depth simulation pressure vessels; mud pumps and mud handling room; controls area, and service corridor where rock specimens are prepared.

Rig Room - The rig room is a 1500 square foot, 50 foot high bay housing the drill rig, drilling pit, simulation pressure vessels and a rock storage pit. A 10-ton overhead crane allows the handling of laboratory vessels and equipment, rocks and downhole tools.

Drill Rig - The drill rig (Figure A2) is a rail-mounted movable gantry that can be positioned over various stations for atmospheric and pressure drilling. The drilling platform can be located at a number of heights and is adjustable within the main frame of the rig to accommodate various length tools. The platform contains a rotary table with DC motor drive to allow continuously variable rotation from 0 to 500 RPM and torques up to 5,000 foot-pounds. Hydraulic cylinders and a servocontrolled hydraulic power supply provides a drilling stroke of six feet at penetration rates up to 100 feet per hour. Thrust can be applied up to 400,000 pounds as required to supply bit weight and overcome the pressure reaction from simulated wellbore pressure.

Drilling Pit and Simulators - The drilling pit is a 23-foot deep reinforced concrete sub-floor structure with two additional cased holes extended 16-feet and 36-feet from the bottom of the pit floor. Three pressure vessels are housed in the drilling pit, including the wellbore simulator, geothermal vessel and the long downhole tool vessel.

The wellbore simulator (Figure A3) is the converted breech end of a naval gun barrel with a 23-inch inside diameter, 18-foot overall length, working pressure of 20,000 psi and a working length of 7-feet. Cylindrical rock specimens up to 20-inch diameter by 7-feet long can be subjected to independently controlled confining pressure, overburden stress and pore pressure simulating well depths to 30,000 feet.

The wellbore pressure is maintained by pumps and a choke system. A specially developed rotary seal around the polished drill shaft allows the shaft to rotate under pressure. High pressure drilling mud and rock cuttings flow out of the wellbore into a second long vessel before pressure is relieved. There the cuttings are screened out before the mud passes through a remotely adjustable choke to reduce pressure prior to returning to the mud pit. Several rock specimens are prepared in advance with metal end caps and sealing jackets to be inserted and removed from the wellbore simulator as part of the vessel's top sealing plug.

Mud Pump and Mud Handling Room - The laboratory is equipped with complete mud handling equipment and mud pumps, including a 20,000 gallon mud storage capacity; two 40-HP centrifugal circulating and charging pumps; a 58P Oilwell Triplex mud pump driven by a 125-HP DC motor rated at 600 psi at 360 GPM; and an FA 1600 Continental Emsco triplex mud pump driven by two 900-HP DC motors presently equipped with five inch liners and rated at 6,000 psi and 360 GPM. Currently, new fluid ends based on the Exxon high pressure fluid end design are being fabricated to provide the capability of 12-15,000 psi and 200 GPM needed to create wellbore pressure for simulating wells to 30,000 feet. The DC motor drives allow continuously variable flow rate at constant pressure.

Instrumentation and Controls - The drill rig and wellbore simulator are instrumented with numerous transducers to measure the various pressures and temperatures, as well as bit weight, torque, rotary speed, penetration, penetration rate and flow rate. These measured parameters are recorded on analog X-Y-Y' and strip chart recorders and a digital computer. The operation is controlled from the remote instrumentation station. The servocontrolled drill rig allows automatic control of either constant bit weight, constant penetration rate or constant torque.

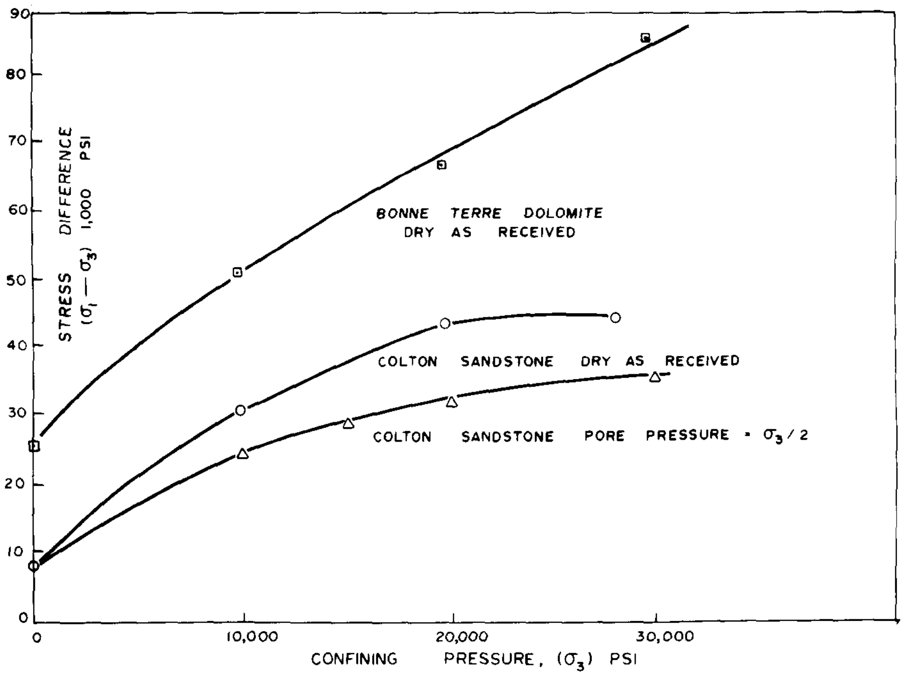

FIGURE 1

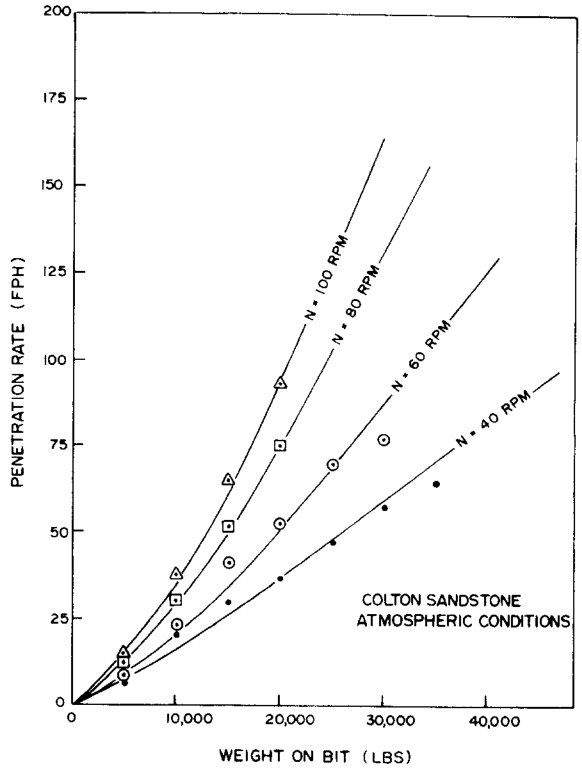

FIGURE 2

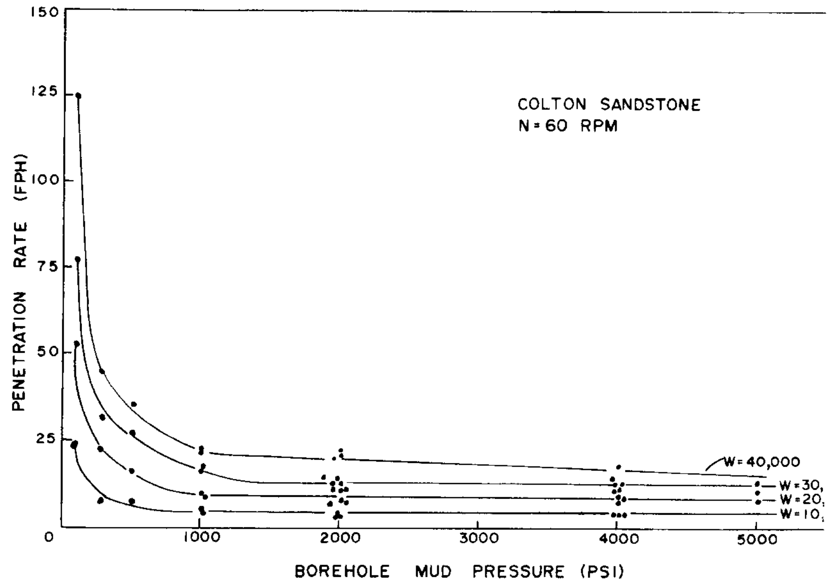

FIGURE 3

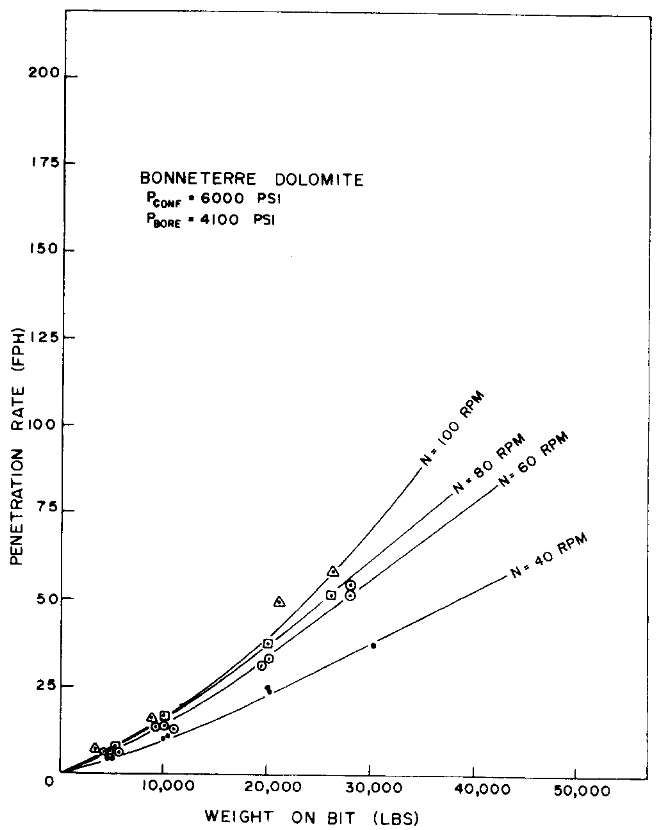

FIGURE 4

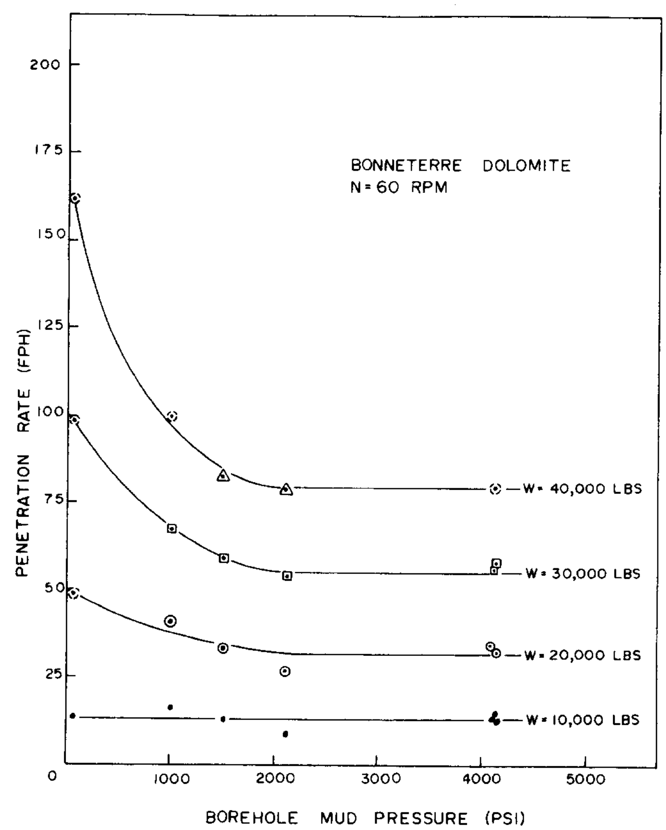

FIGURE 5

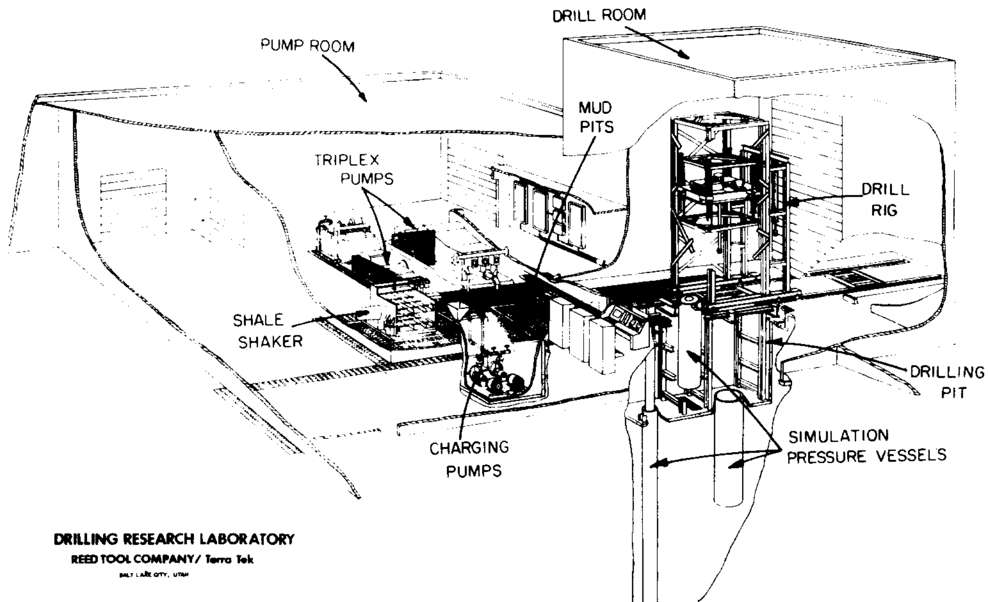

FIGURE A1

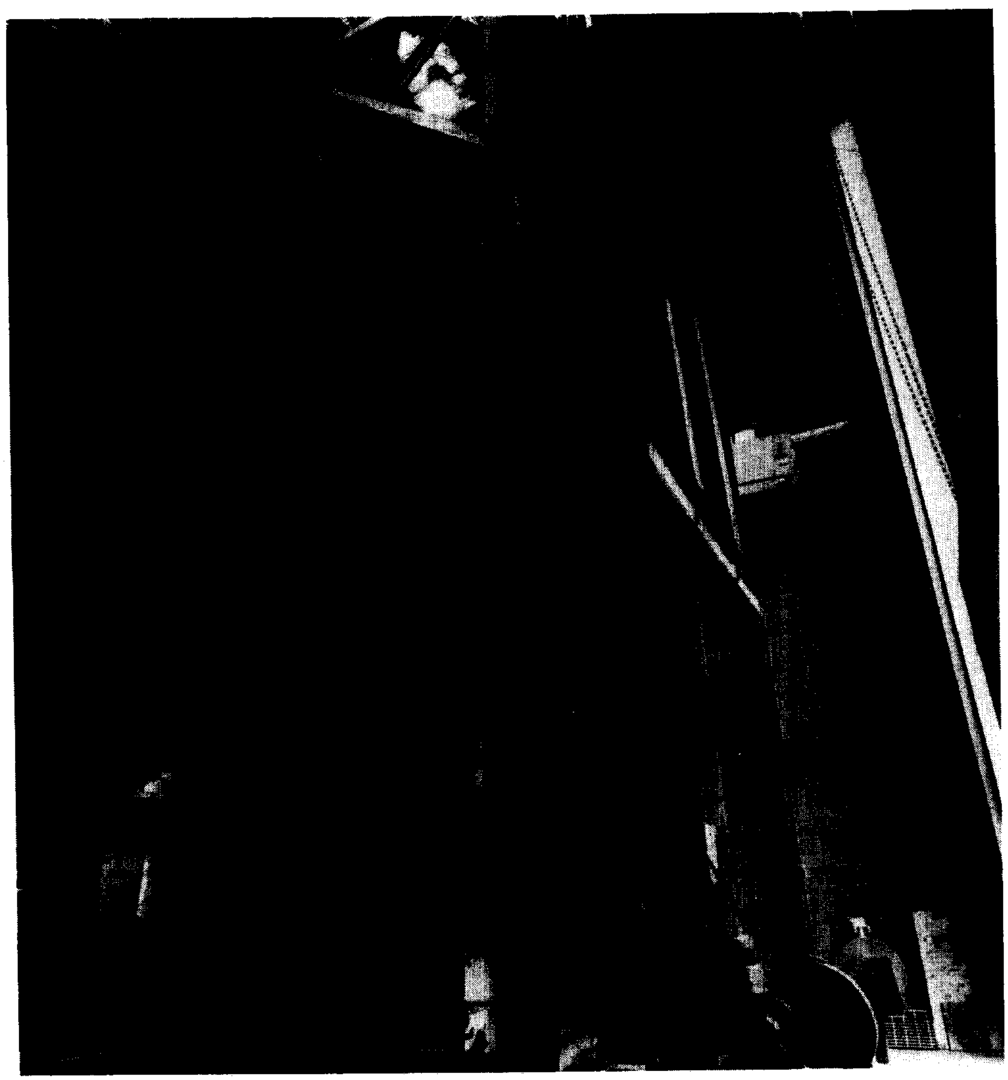

FIGURE A2

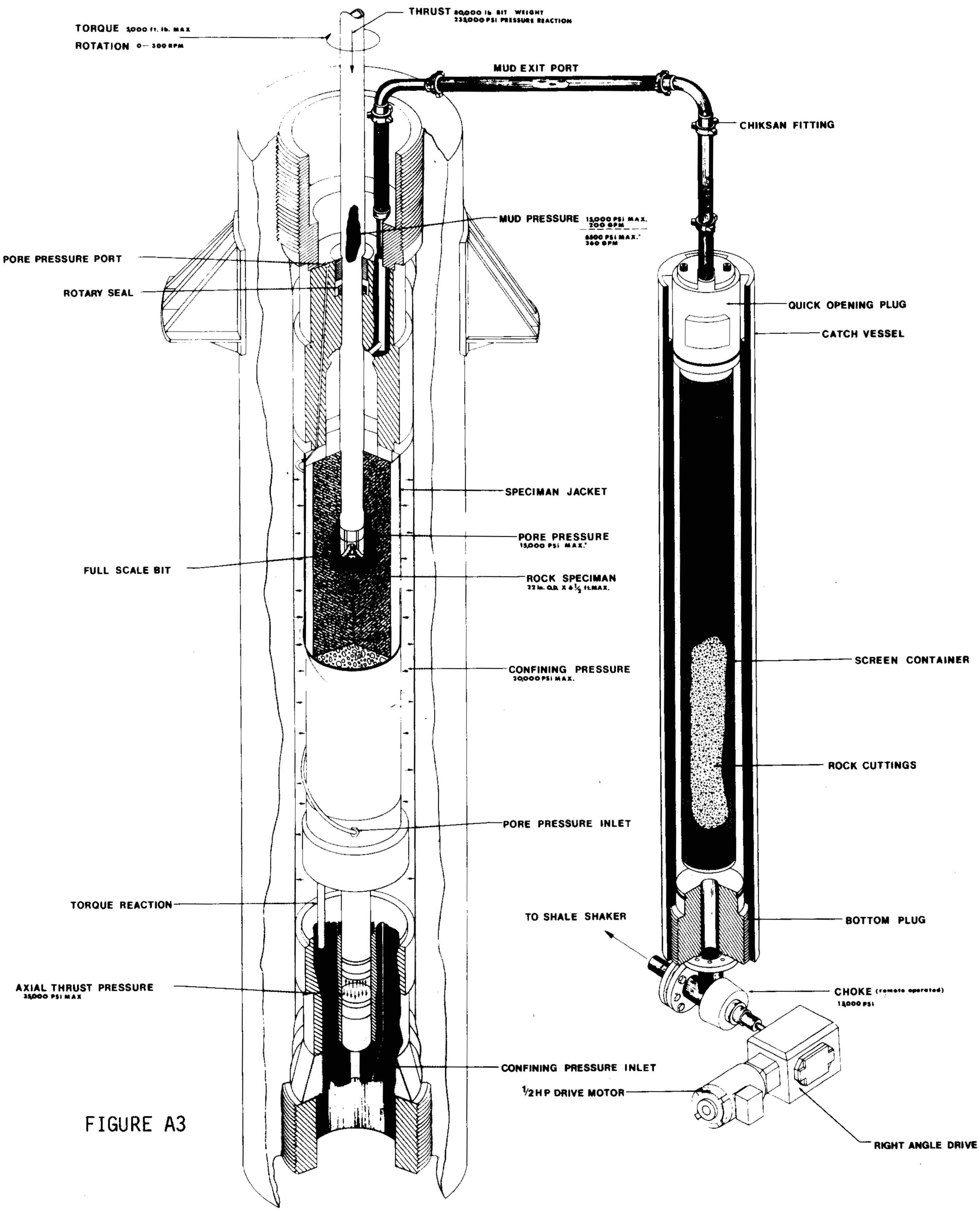

FIGURE A3

DRILLING RESEARCH LABORATORY - WELLBORE SIMULATOR

TABLE 1
MECHANICAL AND PHYSICAL PROPERTIES OF TEST ROCK

	COLTON SANDSTONE	BONNE TERRE DOLOMITE
TOTAL POROSITY (% of Total Volume)	10.95%	8.42%
AIR VOIDS (% of Total Volume)	8.94%	8.01%
INITIAL SATURATION (% of Pore Volume)	18.37%	4.84%
DENSITY (As Received)	2.38 gm/cm^3	2.66 gm/cm^3
DRY DENSITY (Sample Dried 24 hours @ 105°C)	2.35 gm/cm^3	2.656 gm/cm^3
GRAIN DENSITY	2.65 gm/cm^3	2.90 gm/cm^3
PERMEABILITY (With P_{conf} @ 5,000 psi)	40 x 10^{-6} darcies	47 x 10^{-9} darcies
UNCONFINED STRENGTH	7,600 psi	25,500 psi
COMPRESSIONAL WAVE VELOCITY	2876 M/Sec	6513 M/Sec
SHEAR WAVE VELOCITY	1963 M/Sec	3588 M/Sec
YOUNG'S MODULI	2.83 x 10^6 psi	12.73 x 10^6 psi

TABLE 2

MUD PROPERTIES

BASE: Water

PHASES: (i) Water
(ii) Solids
(a) Bentonite
(b) Barite
(c) Drill Solids

WEIGHT: 9.3 pounds/gallon

APPARENT VISCOSITY: 12 cp

PLASTIC VISCOSITY: 7 cp

YIELD POINT: 10 pounds/100 square feet

INITIAL GEL: 5 pounds/100 square feet

10 MINUTE GEL STRENGTH: 14 pounds/100 square feet

pH: 7.85

API FILTRATE: 14.2 cc/30 minutes

APPENDIX B

EXPERIMENTAL DATA FOR COLTON SANDSTONE

BIT	CONFINING PRESSURE (psi)	RAM PRESSURE (psi)	MUD PRESSURE (psi)	MUD FLOW (gpm)	ROTARY SPEED (rpm)	BIT WEIGHT (1000 lbs)	DRILLING RATE (ft/hr)	TORQUE (ft. lbs)
SMITH F-3 7 7/8 Inch w/3- 11/32 Nozzles	Atmos.	Atmos.	100	220	40	5	6.1	400
						10	20.6	830
						15	30.1	1320
						20	36.4	1950
						25	47.0	- -
						30	57.5	- -
						35	64.5	- -
					60	5	8.0	400
						10	23.8	800
						15	41.0	1200
						20	53.0	1800
						25	70.0	- -
						30	77.5	- -
					80	5	12.0	350
						10	30.5	730
						15	52.0	1070
						20	75.5	1380
					100	5	14.1	230
						10	37.3	580
						15	65.0	960
						20	93.5	1240
	1500	2470	275	220	60	10	7.7	440
						20	22.2	1000
						30	31.8	1600
						40	44.9	- -
			500	220	60	10	7.4	420
						20	15.8	1000
						30	27.4	1700
						40	35.4	2200
			1000	220	60	10	5.3	400
						20	9.9	940
						30	16.9	1600
						40	21.3	2100
	3000	4940	1000	220	60	10	4.8	400
						20	9.2	880
						30	17.6	1440
						40	22.6	2040
			2000	220	40	10	3.4	400
						20	6.5	900
						30	9.0	1480
						40	17.8	2280
					60	10	3.9	380
						20	7.8	840
						30	10.4	1400
						40	14.6	2000
					80	5	5.4	200
						10	9.0	400
						20	11.5	880
						30	19.0	1460

BIT	CONFINING PRESSURE (psi)	RAM PRESSURE (psi)	MUD PRESSURE (psi)	MUD FLOW (gpm)	ROTARY SPEED (rpm)	BIT WEIGHT (1000 lbs)	DRILLING RATE (ft/hr)	TORQUE (ft. lbs.)
SMITH F-3 7 7/8 Inch w/3-11/32 Nozzles	3000	4940	2000	220	80	40	27.4	2160
					100	5	5.8	200
						10	7.6	400
						20	14.1	880
						30	20.5	1400
						40	28.0	2000
				80	60	10	7.1	400
						20	9.9	950
						30	11.6	1500
						40	16.9	2150
				150	60	10	4.8	440
						20	9.1	950
						30	13.8	1560
						40	17.8	2200
				220	60	10	7.9	400
						20	11.1	840
						30	13.8	1500
						40	20.2	2100
		3500	2000	220	60	20	9.8	900
						40	21.6	2150
		4500	2000	220	60	20	11.8	1000
						40	22.0	2200
		5500	2000	220	60	20	9.7	940
						40	19.8	2150
	6000	9870	2000	220	60	5	3.2	200
						10	3.6	400
						10	4.8	400
						20	11.0	840
						20	7.8	1000
						30	12.8	1600
						30	14.6	1500
						40	22.7	2200
						40	21.7	2200
			4000	220	40	5	3.2	230
						5	2.7	--
						5	3.6	240
						10	5.1	400
						10	5.2	480
						15	4.8	650
						20	6.1	900
						20	8.0	960
						30	11.2	1440
						40	13.8	2000
					60	5	3.0	200
						5	4.0	--
						10	4.7	--
						10	4.6	400
						20	7.1	800
						20	9.0	--
						30	10.6	1400
						30	12.8	--
						30	12.5	1600

BIT	CONFINING PRESSURE (psi)	RAM PRESSURE (psi)	MUD PRESSURE (psi)	MUD FLOW (gpm)	ROTARY SPEED (rpm)	BIT WEIGHT (1000 lbs)	DRILLING RATE (ft/hr)	TORQUE (ft lbs)
SMITH F-3 7 7/8 Inch	6000	9870	4000	220	60	40	13.8	2000
					100	5	3.5	200
						10	5.1	400
						20	8.6	820
						30	12.7	1360
						40	17.8	1900
	9000	14810	4000	220	60	10	4.6	400
						20	9.6	800
						30	11.4	1500
						40	18.7	2100
			5000	220	60	10	9.2	480
						20	10.7	1000
						30	12.9	1550

EXPERIMENTAL DATA FOR BONNE TERRE DOLOMITE

BIT	CONFINING PRESSURE (psi)	RAM PRESSURE (psi)	MUD PRESSURE (psi)	MUD FLOW (gpm)	ROTARY SPEED (rpm)	BIT WEIGHT (1000 lbs)	DRILLING RATE (ft/ hr)	TORQUE (ft lbs)
SECURITY M89TF 7 7/8 Inch w/3 - 11/32 Inch Nozzles	Atmos.	Atmos.	50	220	40	5	3.8	90
						10	12.6	320
						20	33.4	800
					60	5	4.2	70
						10	14.2	260
					80	5	6.4	70
						10	20.7	260
					100	5	8.4	70
						10	26.6	260
	3000	4940	1000	220	60	10	16.0	360
						20	41.1	800
						30	67.5	1200
			1500	220	60	5	5.3	100
						10	13.8	300
						20	33.0	750
						30	58.3	1220
						40	82.5	1800
			2100	220	60	5	3.9	100
						10	8.9	310
						20	27.0	780
						29	54.7	1200
						38	70.5	1800
	6000	9870	4100	220	40	5	4.8	220
						5	4.7	260
						10	10.1	400
						10	10.4	500
						20	24.5	940
						20	25.1	1100
						30	37.8	1490
					60	5	6.6	--
						5	6.9	--
						5	6.6	--
						10	14.6	--
						10	14	--
						10	13.5	--
						20	34.2	--
						20	34.0	--
						28	54.6	--
						28	53.6	--
					80	5	7.4	--
						10	17.2	--
						20	37.8	--
						26	52.3	--
					100	5	7.0	--
						10	16.4	--
						21	50.3	--
						26	59.0	--

ROCK MECHANICS ASPECTS OF MHF DESIGN IN EASTERN DEVONIAN SHALE GAS RESERVOIRS

by

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ABSTRACT

As part of an ERDA/OGST program, rock mechanics considerations are used to help design a deeply penetrating hydraulic fracture in Devonian shale at a Columbia Gas System Service Corporation well in Lincoln County, West Virginia. Rock properties of the pay zones were considered in relation to the barrier formations. Formation properties--specifically, elastic moduli critical stress-intensity factor and the minimum *in situ* stress--were determined from laboratory core measurements and field tests. Analyses using the formation properties above suggest that the Middle Brown shale zone is the layer (in the Devonian shale) that is most likely to "contain" a hydraulic fracture. That is, a fracture containment analysis indicated that the Gray shales on either side of the Middle Brown shale would act as barriers to fracture growth, provided the fracture fluid is injected at a pressure that does not exceed a naturally occurring stress in the reservoir rock by more than about 400 psi. Fractures initiated in the Gray shales would be expected to move out of zone.

INTRODUCTION

The eastern Devonian shales represent a potential gas reservoir of enormous size [Ranostaj, 1976]. Unfortunately, the reservoir consists of tight formations that require stimulation before economical gas production can be obtained. Massive hydraulic fracturing represents a possible stimulation technique for these formations. Under contract #(46-1)-8014 from the Energy Research and Development Administration, Columbia Gas System Service Corporation has been assigned the tasks of:

1) determining the technical and economic feasibility of hydraulic fracturing in Devonian shales, and
2) identifying the fracture distribution, gas distribution, and ways to achieve economic production by application of stimulation research findings.

To acccomplish these objectives, a three-well program [Ranostaj, 1976] was planned in Lincoln County, West Virginia; see Figure 1. Different hydraulic fracture treatments were planned for the first two wells in order to obtain data necessary to optimize the stimulation treatment in the third well. Terra Tek, under subcontract from Columbia Gas, was to determine the mechanical

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Prepared for ERDA under Contract No. E(46-1)-8014.

characteristics of the formations to better design and interpret the results of the massive hydraulic fracturing (MHF) tests.

The Devonian shale in the area of the three-well test program consists of several layers of Brown and Gray shale as shown in Figure 2. Natural gas is found in all of the layers with the Middle and Lower Brown areas having the best potentials. Since the underground bedding is nearly horizontal and there are no major tectonic displacements in the area of the test program, the shale layers are expected to be similar in the 20401, 20402 and 20403 wells. Data from all three wells are thus combined to form a composite picture for the area.

In hydraulic fracturing of underground rock formations, the rock is subjected to: 1) the fracturing fluid pressure which tends to open the crack, 2) the far field *in situ* stresses acting to close the crack and 3) the fracture toughness of rocks, a material property similar to the tensile strength that represent the resistance of rock to fracturing. During a hydraulic fracture treatment, the forces from the treatment fluid need to overcome both closing forces from the stress in the ground and the rock's resistence to fracture.

In a layered underground formation such as the Devonian shale, the separate layers may have different fracture toughnesses, and/or elastic moduli along with different natural occurring stresses in the ground. Fracture containment analysis is accomplished by evaluating these factors as they apply to the particular zone of the gas reservoir being stimulated. To determine whether a layer is a barrier or not, it is thus necessary to determine its properties in relation to the adjacent layers. A particular layer may be a barrier in some instances and not a barrier in other instances depending on the relative relationship of the stresses and mechanical properties.

CONTAINMENT CRITERIA

When a fracture is initiated in the rock, the fracture will extend when the stress-intensity factor at its tip reaches a critical value. Whether a fracture moves up, down or out depends on the relative values of the critical stress-intensity factors for the various materials and the stress-intensity factors along the fracture perimeter as generated by the loading conditions and fracture geometry. A fracture analysis can be made by determining the stress intensities and comparing them to the critical values [cf. Simonson *et al* 1975]. The following data are used in such analysis:

1) The elastic moduli in the pay zone and bounding layers.
2) The *in situ* stress field and, in particular, the minimum principal stresses in the pay zone and the bounding layers above and below the pay zone.
3) The fracture toughness or critical stress-intensity factors for the pay zone and the bounding layers.
4) The fracturing fluid and the pump schedule.

Knowledge of the elastic moduli and *in situ* stresses for the pay zone and both of the bounding layers is needed to determine whether or not the bounding layers are barriers to crack extension outside the pay zone.

Hydraulic fracture analysis is inherently a three-dimensional problem; the mathematical solutions of which are extremely complicated. The present work will be limited to treating two-dimensional cracks. Such simplified analysis provides considerable insight into understanding these parameters and conditions whcih influence hydraulic fracture propagation [cf. Simonson *et al* 1976].

The basic concept of containment analysis is illustrated in Figure 3. The fluid is moving such that the pressure near the well-bore is higher than the pressure near the tip. Each of the three layers has its own critical stress-intensity factor, elastic moduli and *in situ* stresses. Estimates of the stress-intensity factor at the edges and tip of the propagating fracture can be made if the pressure profile, *in situ* stresses and elastic moduli along with the crack shape are known. These estimates are then compared to the critical stress intensities. The fracture will propagate where the stress-intensity factors reach the critical values. In the special case where the stress-intensity factor would be equal to the critical value at all points on the perimeter around the crack, then the fracture would propagate in all directions at the same time. On the other hand, if the stress-intensity factor reaches a critical value only at the tip and not at the upper and lower edges, the fracture is confined to the pay zone.

The stress-intensity factor at the fracture tip is calculated from the pressure inside the fracture, the *in situ* stresses, and the fracture geometry. For this discussion, we will consider a long narrow crack in an infinite material. This model is representative of a hydraulic fracture with a short height and a long length. The plane strain mathematical model gives the following equation for the stress-intensity factor at the upper and lower crack tips

$$K_I = \frac{1}{\sqrt{\pi \ell}} \int_{-\ell}^{\ell} (P_y - S_y) \sqrt{\frac{\ell + y}{\ell - y}}\, dy$$

where

P_y = pressure profile in crack

S_y = far field horizontal stress profile

y = position along crack

ℓ = height from crack center to the tip.

Since fractures propagate normal to the minimum principal stress, S_y represents the minimum principal *in situ* stress. Note in this equation that the stress-intensity factor is dependent on the profile of the stress difference between the pressure inside the fracture and the native *in situ* stresses across the fracture. Different combinations of fluid pressures and *in situ* pressures will give different values for K_I and in turn different results for a prediction of the final fracture geometry.

The above equation for K_I is for the hypothetical case where the elastic moduli of the pay zone and the bounding layers are equal. If the elastic moduli of the several layers are different, then there is an additional influence on the stress-intensity factor as a result of the differences in the moduli. Figure 4 illustrates the qualitative behavior of the stress-intensity factor for a crack that moves perpendicular to an interface between two materials with different moduli when the horizontal stresses are uniform across the bounding layers. If the elastic moduli in the pay zone is hgiher than that of the bounding layer, then as the fracture propagates towards the boundary the stress-intensity factor increases such that it will reach the critical value and the fracture will "snap" into the bounding layer. On the other hand, if the moduli in the pay zone are lower than the moduli in the bounding layer, then a fracture which is propagating from the pay zone toward the bounding layer will find the stress-intensity of its tip nearest the interface becoming less and less as the boundary is approached such that the critical value is not reached and the fracture is contained with in the pay zone.

Differences in *in situ* stress between the pay zone and the barrier layers have a distinct influence on fracture propagation. Consider the hypothetical case shown in Figure 5, in which a hydraulic fracture has extended, by some mechanism or other, into adjacent layers where possibly different tectonic stresses may be acting. Figure 6 shows a plot of the distance the crack has advanced into the region of high stress (the barrier layers) in terms of the pressure P within the fracture and P_0, the fracture fluid pressure required for the fracture to reach the interface. The curves in this figure are for a crack height of 200 ft., a fracture toughness of 1000 psi$\sqrt{in}$ and for parametric values of the *in situ* stress difference $S_2 - S_1$. For a stress difference of 1100 psi, for example, an overpressure of 500 psi would be expected if the fracture were to propagate a distance of 100 ft into the region of higher *in situ* stress.

If the *in situ* stress in the barrier layer (S_1) was less than the *in situ* stress in the pay zone (S_2), a situation would exist where it requires less pressure to propagate the fracture in the barrier than in the pay zone.

These principles will be used to design deep-penetrating hydraulic fractures in Devonian shale.

SUMMARY OF ROCK MECHANICS DATA

Ultrasonic velocities and elastic moduli were determined for cores taken from several layers in wells 20402 and 20403 [Lingle and Abou-Sayed, 1976]. The effect of confining pressure on the measured velocities was very small, on the order of 2 percent for pressure ranging from atmosphere to 4000 psi. Also, the changes in velocities with temperature over the range encountered in these wells ($\sim 100^\circ F$) was less than one percent for the p-wave and within the accuracy of the measuring system for the s-wave.

Figure 7 shows the comparison of laboratory data with that obtained from logs. The p-wave velocities and densities are, in general, in good agreement, with the exception of the sample from 3910 feet. The laboratory s-wave velocities (measured with the same polarization as the logs) are consistently 10 to 12 percent higher than the log values at identical depths. This is possibly the result of the logs detecting the arrival of surface waves and not the s-waves [Lingle and Jones,1977]. With this assumption, the revised s-waves velocities are shown to agree very well (within 0.5 percent) on the average with the laboratory measured s-waves velocities.

Young's modulus has been calculated using the measured bulk densities, p-wave velocities and the revised s-wave velocities. For the purpose of these calculations, the material was assumed isotropic and homogeneous. Figure 8 illustrates the general trend of the data. Also shown are results of triaxial compression for the Upper Brown and Lower Gray shales. As expected, the static moduli are lower than the sonic moduli; for the samples tested the difference is on the order of 20 to 30 percent.

Critical stress-intensity factors were determined experimentally for the Gray shales by internal pressurization of cylinderical sample with two radial prenotches. The method was developed by Clifton *et al* [1976]. In this method a sample of the core about 2-3 inches long has a small hole drilled along the axis and notches placed in the walls of the small hole to specify the fracture initiation points. A bladder is placed in the hole to prevent fluid from entering the sample or the notches and then pressure is applied in the bladder until the sample bursts. Figure 8b summarizes the results for the Gray shales.

In situ stresses, especially the differences in *in situ* stresses between the pay and barrier formations, are the most critical parameters to MHF containment. Unfortunately, this is the parameter for which the least amount of data is available. A single mini-hydraulic fracturing test was performed by Terra Tek at the 2745 ft. level (Upper Gray shale) in well #20402 [Abou-Sayed *et al* 1977]. These results were as follows:

Minimum Horizontal Stress	= 2360 psi	N 40°W to N 45°W
Maximum Horizontal Stress	= 4390 psi	N 45°E to N 50°E
Overburden Stress	= 3210 psi	
Pore Pressure	≃ 250 psi	

The measured principal stress directions agree well with the prevailing geological structure in the region and with the principal stress directions reported by Overbey [1976] from a series of measurements in West Virginia. A basement structure map of the region in which the reported test was conducted is shown in Figure 9. The map, adapted from Harris (USGS Map I-919 D, 1975) by Overbey [1976], shows a projection of the Rome Trough through the northwestern edge of West Virginia. Schumaker [1976] describes the Rome Trough as a graben bounded by high-angle, normal faults. This structure lies within an area which is a junction of three distinct geological provinces [Werner, 1976].

1) Central Appalachian Fold Belt
2) Southern Appalachian Thrust Fault Belt
3) Appalachian Plateau with Basement Faults

Although it is not known whether or not the basement faults penetrate into the Devonian shales in this area, Overbey's measurements [1976] suggest a correlation of principal stress directions with the basement structure. At locations which fall outside the projection of the Rome Trough, the measured direction of σ_{HMAX} are oriented generally E-W and are normal to the predominately N-S strike of the thrust faults and foldings of the Appalachian Mountains. Measured directions of σ_{HMAX} which fall within the projection of the Rome Trough trend N45°E to N50°E, or parallel to the strike of the basement faults and in agreement with the directions reported here. It is not yet clear why stresses relating to the large scale deformation and mountain building during the Paleozoic Era should still remain a controlling factor in this region.

Since the complete geological structure in this region does appear to be related to the measured orientation of the stress field, an estimate of the minimum horizontal stresses in the other shale layers was made on the basis of elastic theory. Data from the Upper Gray shale was anlyzed for determination of applied boundary displacements in both horizontal directions as might be imposed through normal faulting on the boundaries of the Rome Trough. These same displacements were applied to the other shale layers and the resulting minimum *in situ* stresses in these layers were estimated using moduli derived from the corrected logs. Figure 8c shows a plot of the estimated minimum horizontal principal stresses in the different formations.

These estimates correlate with two independent observations. Swolfs *et al* [1977], based on strain relaxation data, estimated minimum *in situ* stress gradients of 0.52 psi/ft for the Middle Brown shale and 0.76 psi/ft for the overlying Middle Gray shale. These coincide with the data shown in Figure 8c at the Middle Gray shale/Middle Brown shale interface. Field engineers contend that the Lower Brown shale will break down under a head of water. The estimated minimum *in situ* stress shown in Figure 8c also would predict this behavior.

DATA INTERPRETATION

Although the tests were minimal, sufficient data was gleaned from available information to perform a containment analysis. Both Figure 8a and 8c indicate that the Gray shales and Onondaga Limestone will act as barriers to fracture growth in the Brown shales. The Gray shales are not strong barriers (moduli contrast is less than 30 percent and the largest *in situ* stress difference is less than 800 psi), however, and can also be broken down if fluid pressures are too high.

A significant factor in successful completion of MHF treatment in reservoirs with marginal barrier formations is the control of fracturing-fluid flow rate and the maximum allowable bottom hole treatment pressure (BHTP). There are other factors, besides containment of the induced fracture, that might impose certain bounds on both the flow rate and BHTP such as proppant transport, created crack width, strength of casing, location of perforation and the like. However, the calculated value of BHTP that would prevent deep fracture penetration into the barrier zones would prove instrumental in achieving a contained fracture geometry.

An estimate of the maximum BHTP for a given treatment job can be obtained following the arguments presented earlier. From a pay formation height 2c, the fracture will extend a height ℓ' into the barrier layer for a pumping pressure P given by [Simonson *et al* 1976]:

$$P - S_1 = \frac{1}{\sqrt{\pi(c+\ell')}}\left[K_{Ic} - \frac{2(S_2-S_1)(c+\ell')\cos^{-1}\left(\frac{c}{c+\ell'}\right)}{\sqrt{\pi(c+\ell')}}\right]$$

where K_{Ic} is the critical stress-intensity factor for the barrier layer and S_1, S_2 are the minimum *in situ* stresses for the pay and barrier zones, respectively. Penetration of the fracture initiated in the Middle Brown shale into the Middle Gray shale is shown if Figure 10. For excess pumping pressure in the fracture ($P-S_1$) less than 400 psi, the penetration is kept within 50 ft. Based on the horizontal *in situ* stresses in the Middle Gray and Middle Brown shales, the bottom hole treatment pressure during hydraulic fracturing of the Middle Brown layer should not exceed the minimum horizontal stress in that zone by more than 400 psi, plus any expected drop in pressure across the perforation.

Corresponding considerations for the Lower Brown and Lower Gray shales (the Onondaga Limestone forms a strong barrier) leads to a BHTP of 250 psi in excess of minimum horizontal stress for the Lower Brown shale. Since in treating the Middle Brown shale the fracture will propagate into the Lower Gray shale, there is the possibility of the two fractures interacting. In a multi-stage MHF it is important, therefore, that the better reservoir formation be fractured first.

ACKNOWLEDGEMENTS

It is a pleasure to acknowledge the assistance of Columbia Gas Systems Service Corporation personnel who cooperated on this project. The authors appreciated greatly the assistance and many discussions with Mr. C. Komar, USERDA, Morgantown, during the course of the work. Contributions from Dr. H. Swolfs, Messers. R. Lingle and C. Brechtel of Terra Tek, Inc., are greatly appreciated.

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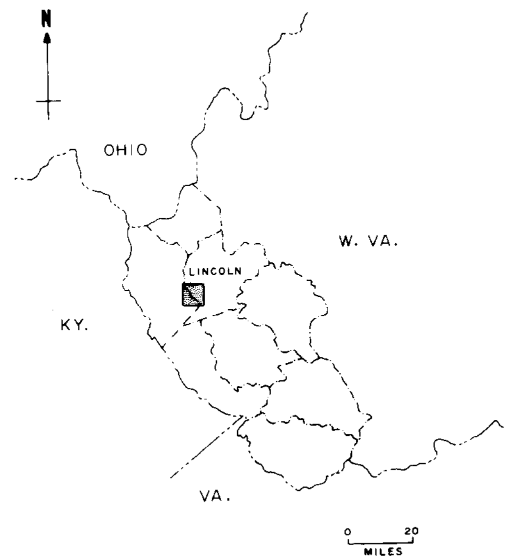

Figure 1. - Location of wells in Lincoln County, West Virginia.

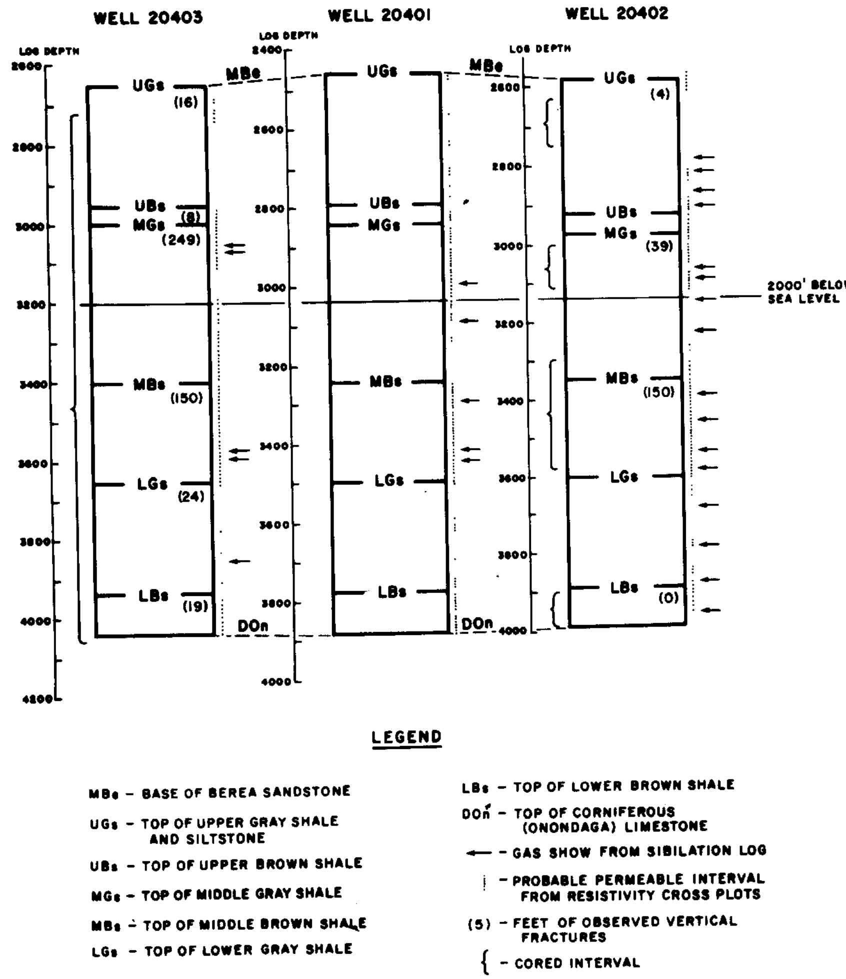

Figure 2. - Summary of geological findings (from Ranostaj, 1976).

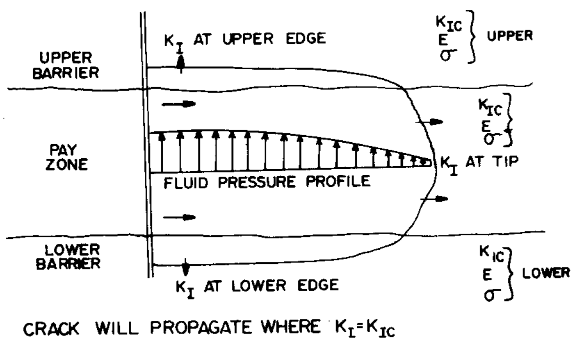

Figure 3. - Schematic diagram to illustrate fracture containment analysis.

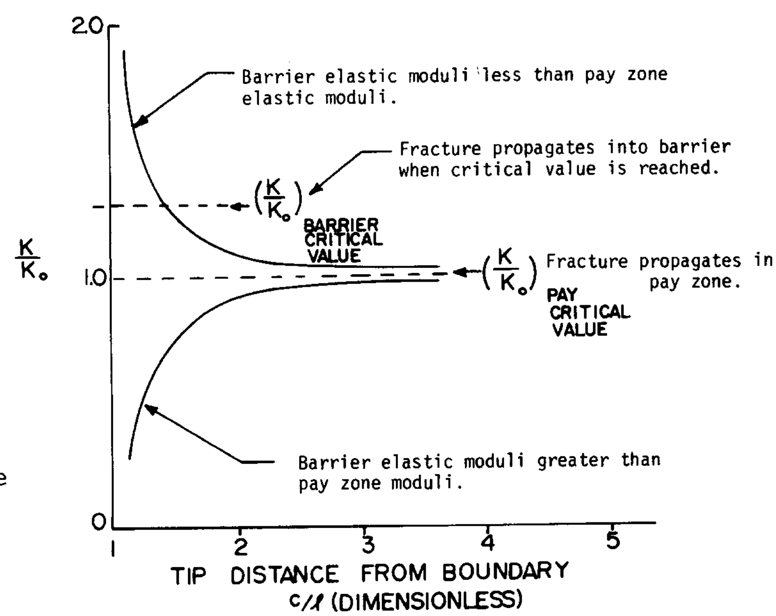

Figure 4.

Qualitative behavior of the stress-intensity factor as a crack of length 2a approaches the boundary of an adjacent layer with different elastic moduli. (c is distance from fracture center to boundary).

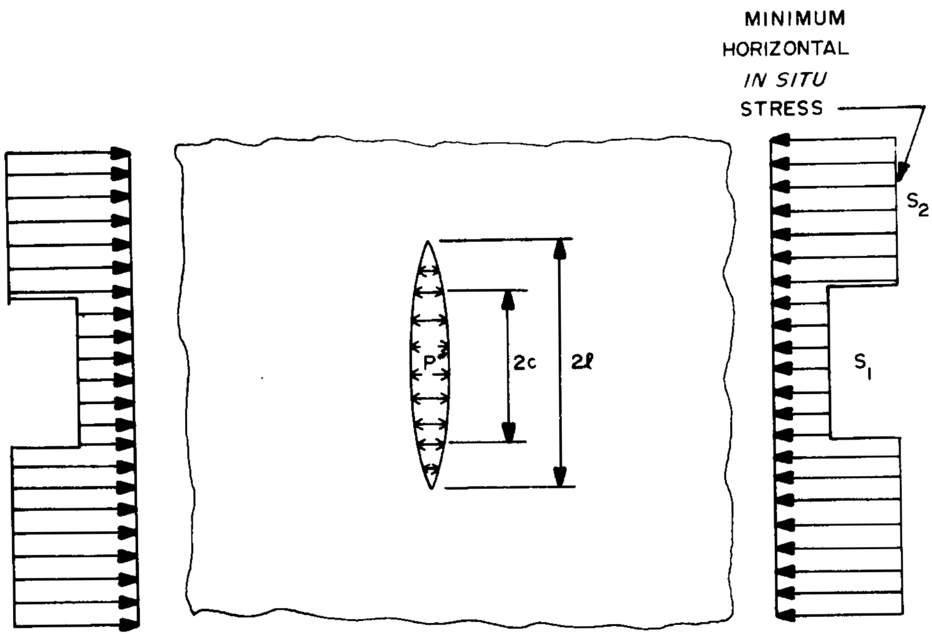

Figure 5. - Vertical hydraulic fracture loaded under uniform pressure (P) with differing minimum horizontal stress in pay zone and barriers.

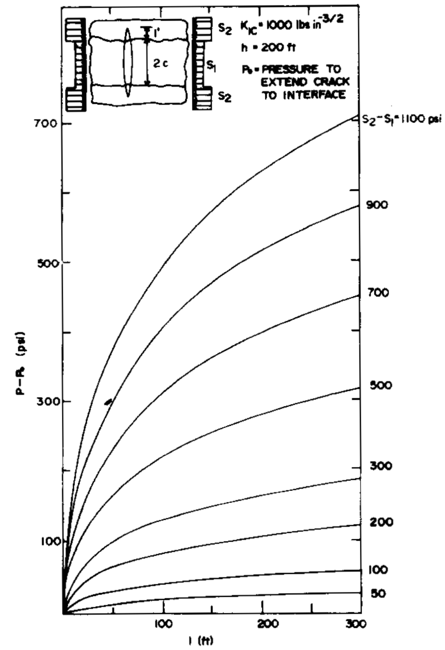

Figure 6.

Estimate of fracture migration into the barrier layers. (from Simonson et al 1976).

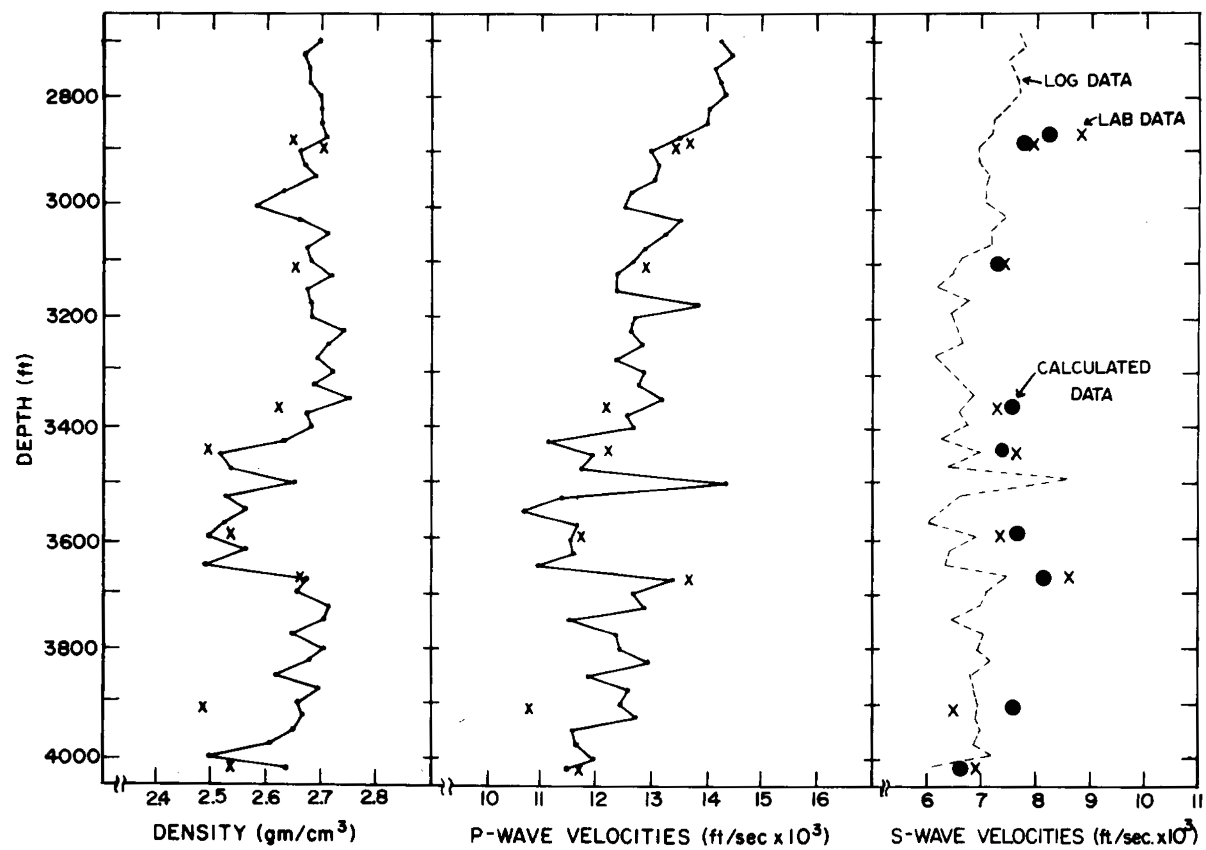

Figure 7. Comparison of laboratory data with log data. Correction to S-Wave assuming that the log detected surface waves is also shown.

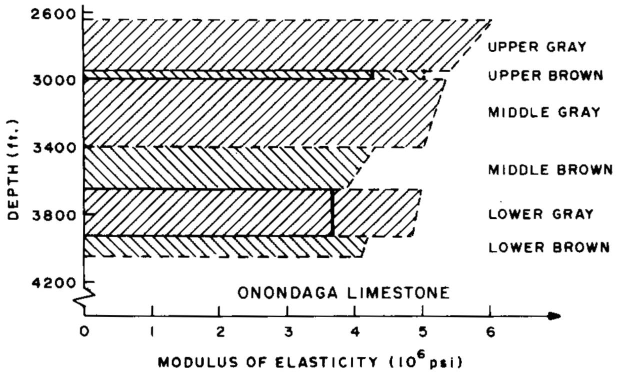

Figure 8a. - Log derived (dotted lines) and laboratory measured (solid lines) modulus of elasticity.

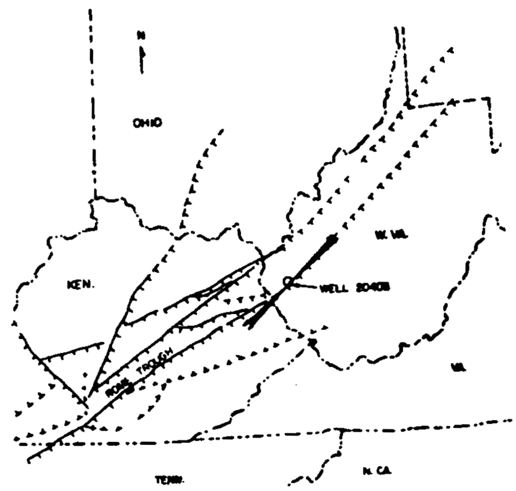

Figure 9. - Basement structure of Kentucky-West Virginia adapted from Overbey (1976) with the direction of maximum horizontal stress at Well #20403.

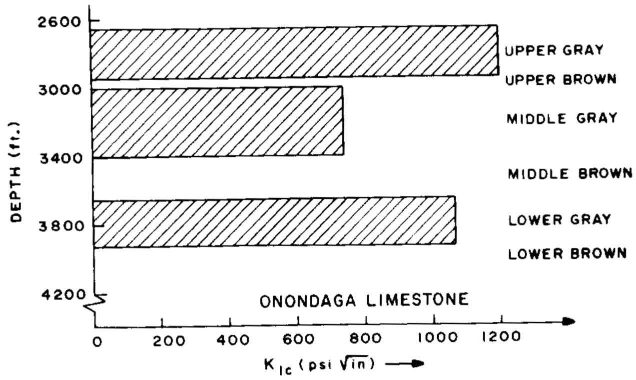

Figure 8b. - Critical stress intensity factor for the shales.

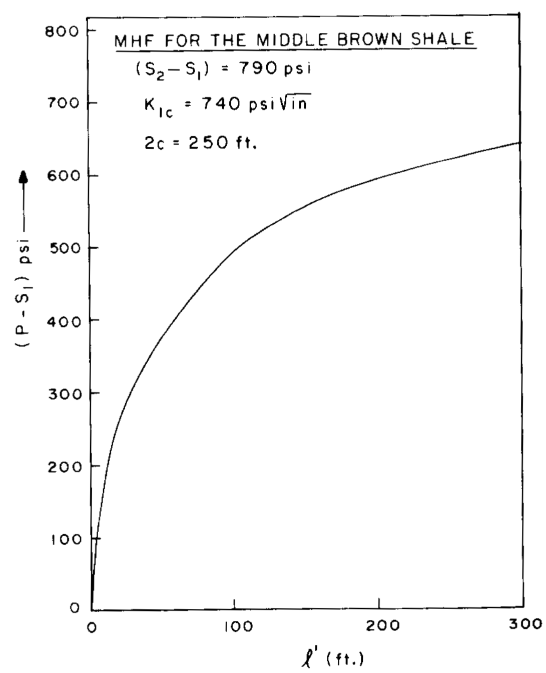

Figure 10.

Fracture penetration into the Middle Gray Shale for fracture in the Middle Brown Shale.

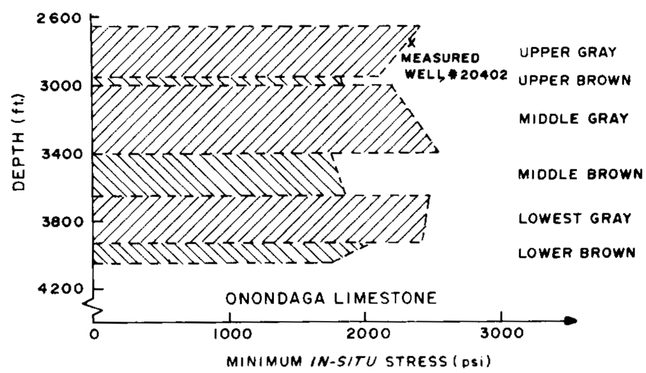

Figure 8c. - Derived minimum in situ stresses correlated to measured stresses (x) at 2745 ft. in Well #20402.

EFFECT OF DRILL-BIT CUTTER OFFSET ON DEEP DRILLING

by

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ABSTRACT

Tests were performed using a single roller cone from a standard drill bit to evaluate the effects of cutter offset angle on drill-bit cutting efficiency in deep wells. For the tests, the *in situ* conditions of a 20,000 foot well were approximately simulated in the laboratory apparatus. A single revolution of the cone-arm configuration was made. A tight sandstone, the same as that used in the ERDA/OGST deep-drilling program (Colton sandstone, 11 percent porosity, 50 μd permeability), was used for five different offsets. Torque, thrust, and volume removed were recorded; preliminary implications that can be obtained for drill-bit design for deep-well drilling will be discussed.

INTRODUCTION

The ERDA-sponsored single cutter drilling tests were conducted to determine the effects of skew on cutting efficiency of roller cones in deep wells. Impetus for this investigation is due primarily to the problem of reduced drilling rates in formations for which continuous plastic (ductile) flow accompanies large deformation rather than brittle failure. Reduction in drilling rates ranging from 30 to 80 percent have been observed in ductile rocks as noted by Cheatham [1977], Murray *et al* [1955], and Eckel [1958], among others. When ductile conditions prevail, simple crushing action normally used in hard rock drilling is not sufficient [Payne and Chippendale, 1953; Cheatham, 1977]. Rather, a scrapping and gouging action in conjunction with crushing has been found to give best results in increasing drilling rates. This action is usually obtained by designing a drilling bit with offset cones using larger tooth spacing and chisel-type inserts. Cone offset simply means that the cone apex leads in the direction of rotation, causing the inserts to drag. However, the additional action of scrapping may casue excessive tooth wear since the mineral abrasiveness may still be quite high although the rock is in a ductile state [Coffman and Connors, 1974]. Excessive tooth wear reduces bit life, thus introducing a trade off between increased drilling

Prepared for ERDA under Order No. BE-00-P-3252.

rates and increased "trip" time caused by bit replacement. Thus, it would be advantageous to optimize the offset angle so as to minimize tooth wear while maintaining respectable drilling rates.

It was decided that an initial series of tests were to be run to analyze the effects of cone offset independent of tooth wear. The *in situ* conditions of a 20,000 foot well were simulated in the test apparatus modified for this work. A single turn of the single cutter was made on the rock specimen with one test run at each of five different offsets (0, 2, 4, 6 and 8 degrees). Torque, thrust, and volume removed were recorded in order to determine specific energy and removal rate for comparison purposes.

TEST SPECIMEN PREPARATION AND APPARATUS

The tests were conducted on 7-1/2 inch diameter samples of Colton Sandstone in a test machine modified for this work. Downhole conditions were simulated in a 60,000 psi capacity, 8-inch I.D., pressure vessel mounted in a 1.7 million pound capacity load frame. This rock had the following properties [Black, Rogers and Wright, 1977]:

Young's Modulus	=	3.1×10^6 psi
Porosity	=	11 percent
Permeability	=	50 microdarcies
Dry Bulk Density	=	2.36 gm/cm^3

All specimens were saturated.

A schematic of the test system is shown in Figure 1. The schematic shows a steel end cap on top of the rock and the rock resting on the drilling chamber. The rock face nearest the bit was angled at 2-1/2^{o}, thus matching the cutter taper at the normal pin angle (36^{o}). The specimen was sealed from the confining fluid using an 0.02 inch thick urethane jacket. The drilling chamber rested on the base plug which was supported by a reaction column, thus transferring the vessel pressure to the load frame.

The schematic also shows a 3-inch-diameter hollow shaft running through a concentric hole in the base plug. Torque and thrust were measured on the shaft inside the drilling chamber using four 350-ohm three-gage rosettes mounted and wired into a four-arm bridge arrangement in order to cancel bending moments. Note that the gages were mounted inside the hollow shaft (separated from the drilling fluid) in a solvent-filled chamber so as not to short-circuit the strain gages. Pressures inside and outside of the shaft were equal.

The cutter was mounted on a 4-3/4-inch-diameter plate bolted to the shaft. The top of the plate was drilled and tapped such that the cutter centerline could be skewed at angles of 0, 2, 4, 6 and 8 degrees from the center of rotation (offsets of 0.064, 0.126, 0.184, and 0.42 inches from the center of rotation). The number one cutter of a Security 4-3/4 inch M88 Tricone bit was attached to the skew plate with a pin angle of 36^{o}.

The shaft was rotated by an Ohio oscillator rotary hydraulic actuator. This was adjusted in order to give 350^{o} rotation at approximately 33 RPM.

The torque and RPM were controlled by a flow control and pressure regulator between a 3,000 psi hydraulic line and the rotary actuator. Thrust was supplied by the servo-controlled bottom actuator of the load frame.

Water was used as the drilling fluid while solvent was used as the confining pressure fluid. Haskel pumps were used for pressurization with drilling fluid pressure being monitored with a Tyco AB pressure transducer and confining pressure being monitored with a Heise pressure gage.

Data was acquisitioned using fast response X-Y recorders. Prior to actual testing, recorder outputs were compared to oscilloscope tracings during simulated cutter tests in order to assure that recorder frequency response did not impare data acquisition. Agreement between recorder and oscilloscope data was within a few percent, indicating that recorder sweep rates were not a problem.

TEST PROCEDURE

A well depth of 20,000 psi was simulated using the following pressure gradients:

Confining Pressure = 2/3 psi/ft depth
Mud Pressure = 1/2 psi/ft depth

Thus, test pressures were 13,300 psi and 10,000 psi for the confining and drilling fluid pressures, respectively. The brittle-ductile transition occurred at confining pressures less than 10,000 psi, indicating that the rock was in a ductile state when tested [Black, Rogers and Wright, 1977]. After reaching pressure, the lower actuator was raised until the bit contacted the rock. The bit was initially inserted 0.1 inch into the rock face using the servo-controller in the displacement feedback mode. The resulting average thrust was $1,000 \pm 200$ pounds. A tooth penetration of 0.1 inch was used in an attempt to standardize initial conditions prior to rotary cutting since control of thrust or torque during the few seconds of test time was not possible. Furthermore, control of initial thrust was not attempted due to the discontinuous nature of the load-penetration plots encountered during tooth penetration, ie., piecewise continuous curves were generated during tooth penetration with numerous load drops occurring, thus making the selection of an initial thrust questionable.

With initial test conditions set, the rotary actuator was activated. A typical torque and thrust record versus time for a 350° rotation at about 33 RPM is shown in Figure 2. After depressurizing, the sample was removed from the vessel and the rock face photographed. Silicone rubber mold material was used to make a cast of the drilled rock and from that the volume removed was determined by weighing.

RESULTS AND CONCLUSIONS

Table I lists the results of the six tests. The table lists offset angle, hole geometry, specific energy and volume removed per hole. For descriptive purposes only, the hole geometry was approximated using a cone with the ratio of the mean base squared over the mean depth ($\bar{b}^2/\bar{p}$). This gives an indication of the change in the hole geometry between the brittle and ductile states. The specific energy was determined by planimetering the area under the thurst and torque curves. The resulting average thrusts and torques were used in the following equation to get the total input energy

$$E_t = \overline{Th}\ P + 2\pi\ \overline{To} \tag{1}$$

where $\overline{Th}$ and $\overline{To}$ are the average thrust and torque, respectively, P is the average penetration of the cutter and 2π is a constant accounting for the circumferential path of the cutter. Only the torque component of the energy need be considered since the contribution from the thrust is neglible.

Table I shows a significant change in hole geometry when comparing unconfined to confined tests. The unconfined test shows a much larger crater area for a given penetration, i.e., more chipping action is observed as would be expected in the brittle state. As the rock becomes ductile, the ratio of crater area to insert area reduces from 2.6 to 1.2 Also, crater area to chip height reduces from 2 inches to 0.4 inches, suggesting that crushing, not chipping, is the predominant mode of material removal. This may be observed to be the case when comparing Figure 3 to Figures 4 and 5.

Table I also shows that the specific energy for the confined test at zero offset was 2.7 times the specific energy for the unconfined zero offset test. The specific energy for the confined tests at the various offsets are difficult to interpret. Figure 6 shows a plot of specific energy versus offset angle. A least square fit to the data would suggest an increase in specific energy with offset. However, because of data scatter, judgement should be reserved as to the quantitative increase in specific energy with skew angle until more data is available.

IMPLICATIONS FOR DESIGN AND FUTURE TESTING

An increase in specific energy indicates that more work must be put into drilling for removal of a unit volume of material. However, such increases in costs caused by more work in drilling using offsets may be compensated by higher drilling rates. Figure 7 shows a plot of average volumes removed per hole versus offset angle, thus giving an indication of the drilling rates. The Figure suggests that the 2 and 4 degree offsets increased volume removal by about 1.7 times the 0 degree offset during confined testing. In comparison the increase in specific energy was only about 1.4 times. Consequently, the preliminary indication is that a 2 to 4 degree offset appears to give near optimum drilling when considering input power and rates of material removal.

Future tests will involve duplication of the 0 and 8 degree offset experiments using 0.1 inch penetration and running three tests at 1 degree offset using 0.05 inch penetration while simulating conditions at depths of 20,000 feet. These tests will be used to indicate data scatter and to give insite into the effect of variable tooth penetration during drilling. Consequently, improvements on cutter penetration measurement are being incorporated prior to the next testing phase in order to provide more stringent control of the test paramters.

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TABLE I - TEST RESULTS

Test	Offset Angle Degrees	Hole Geometry ($\overline{b}^2/p$) inches	Specific Energy 10^6 ft-lb/ft^3	Removed Volume per hole, 10^{-2}in^3
Unconfined	0°	2.00	1.33	1.76
Confined	0°	0.48	3.62	1.25
Confined	2°	0.47	6.29	2.26*
Confined	4°	0.54	5.04	1.93
Confined	6°	0.41	7.20	1.59
Confined	8°	0.40	4.80	1.14

* Note that outer holes were used for the volume per hole calculations to eliminate the indexing effect.

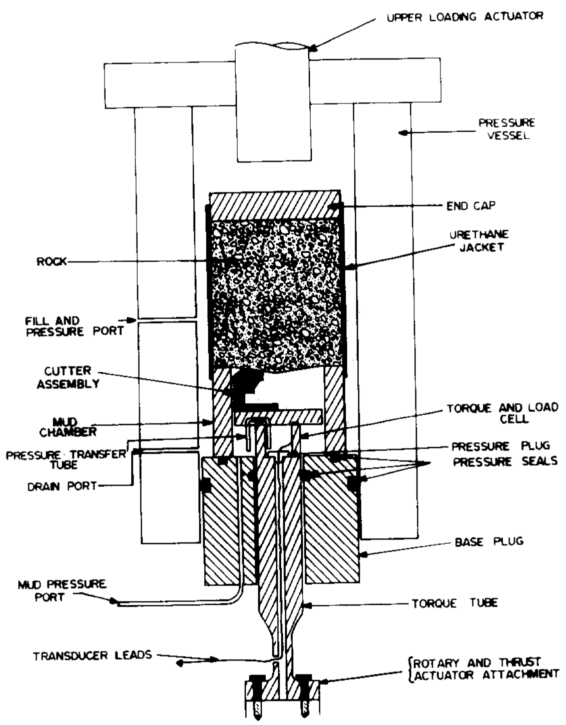

Figure 1. - System schematic.

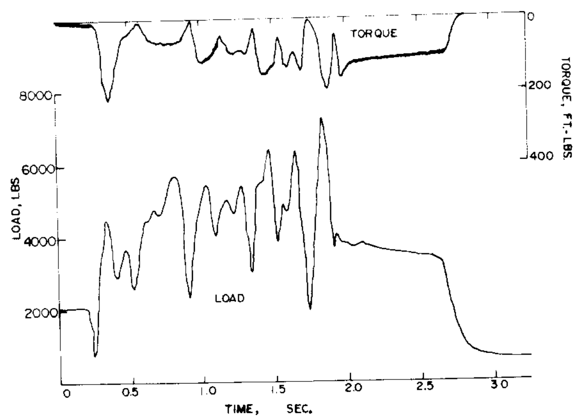

Figure 2. - Typical data tracing of load and torque versus time (confined test 8° offset).

Figure 3. - Unconfined test, zero offsets.

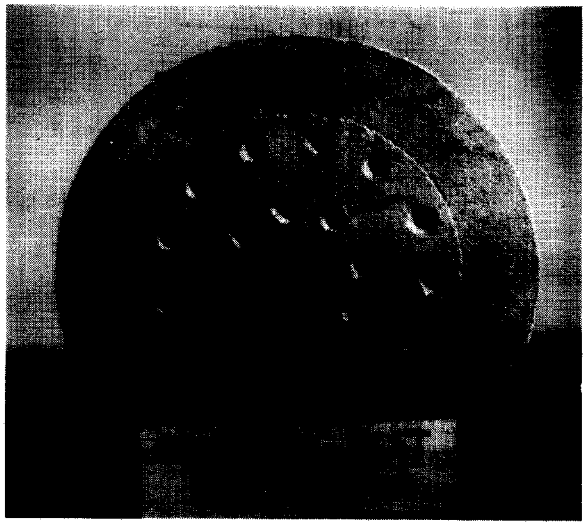

Figure 4. - Confined test,
zero offset.

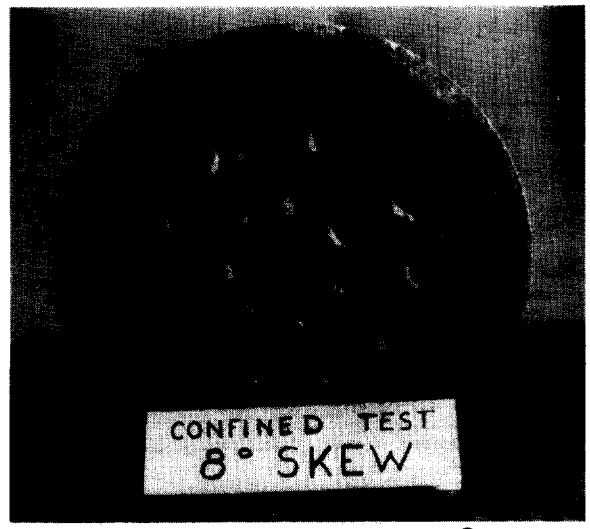

Figure 5. - Confined test 8° skew.
(0.242 inch offset)

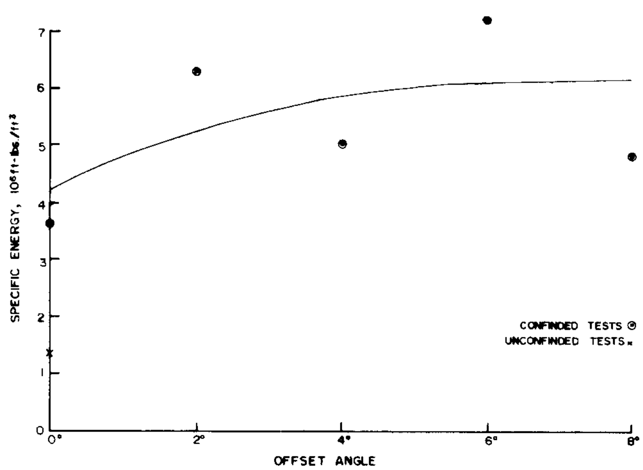

Figure 6. - Specific energy versus offset angle plot.

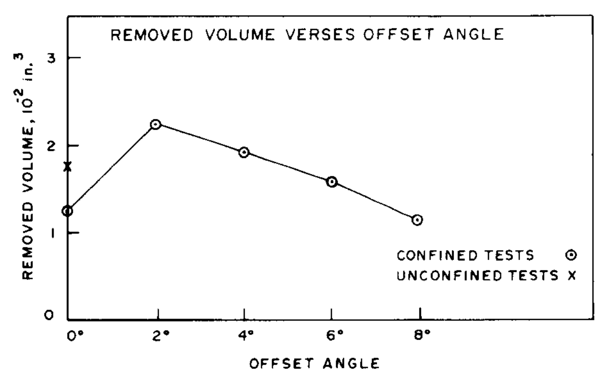

Figure 7. - Removed volume versus offset angle.

SELECTED DRILLING RESEARCH PROJECTS

by

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ABSTRACT

Maurer Engineering is participating in several government and joint industry/government drilling research projects. These include work on downhole motors, new bits, novel drilling systems, offshore technology, drilling fluids, and others. This research is showing great promise of increased drilling capability and reduced drilling costs. Objectives of the projects will be outlined and progress summarized.

Note: Copies of this paper are available from the authors.

TRUE FLUID CORING

by

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ABSTRACT

Secondary and tertiary recovery programs are very expensive to initiate and maintain and careful evaluation of every reservoir being considered is necessary. Unfortunately, current formation evaluation techniques do not provide accurate enough fluid content information to permit sound economic decisions. The ERDA Fossil Fuels Division funded a study to analyze the problem and to identify feasible alternative solutions.

The problems and solutions are reviewed and a feasible Phase I system, which would provide acceptable information accuracy under many conditions, is described. The design of this system is currently being funded by ERDA.

INTRODUCTION

The continued growth in demand for petroleum resources coupled with declining reserves has resulted in increased pressure on reservoir engineers to improve the reliability of their reserve estimates and to evaluate efficiency of recovery techniques. Tertiary recovery systems are extremely expensive and, therefore, accuracy of residual oil saturation estimates is important to risk analysis. Although various logging techniques have been improved significantly in the past few years, the results are still only an indirect measurement of formation properties and the accuracy of interpretation is limited by assumed formation factors. A true fluid coring system would have appreciable application in development of both new and old reservoirs as shown in Table 1.

Several major oil companies have sponsored R&D projects aimed at the accurate determination of fluid saturations in oil and gas reservoirs. All of the major efforts have included taking a core sample of the formation and techniques have centered on controlling the properties of the drilling fluid while coring as a means of reducing or totally eliminating alterations of true fluid saturation. These approaches are extremely costly and in general have not been successful. In addition, they do not prevent changes in the fluid content resulting from reduction in the confining pressure as the core is brought to the earth's surface.

Other techniques have been based on the recovery of core while maintaining a constant bottomhole pressure environment. This method has eliminated one source for error, pressure reduction, but presently available systems do not adequately prevent flushing during the coring operation and lack general operating reliability.

A simple combination of special drilling fluids and a pressure core barrel does not provide the total solution, but may suggest concepts for more sophisticated systems capable of capturing "true fluid" cores.

FEASIBILITY OF A TRUE FLUID CORING SYSTEM

The objective of this entire study was to determine the feasibility of obtaining unaltered true fluid samples of oil and gas reservoirs. After having examined the problem and many alternative solutions, we have determined that there is virtually no probability of obtaining completely unaltered samples. Any technique within the bounds of a practical bore hole size must alter the reservoir slightly. However, there is an acute need for accurate fluid saturation in reservoir production planning. This need is so great that 100% accuracy is not absolutely necessary and a system which approaches true results would be acceptable. It is felt that there is a very good probability that a system can be developed which will give results much improved over present techniques which cause flushing of 50% to 100%. It is desirable to reduce flushing to less than 10%.

The present Loomis pressure coring system, shown in Figure 1, is believed to give results approaching this accuracy under certain field conditions when the system functions properly. The design concepts for a Phase 1 True Fluid Coring System which can routinely and reliably achieve results approaching 90% accuracy is thought to be not only feasible but also within the practical, normal economics of drilling operations.

The development of a Phase 1 system will require several parallel effort programs requiring about 18 to 24 months from inception to field test of a prototype coring system. These parallel efforts include the design and manufacture of a prototype coring system, the laboratory evaluation of the influence of bit design on fluid invasion, the manufacture of an optimum bit design, and the evaluation of drilling fluid additives to reduce fluid invasion. No dramatically new technology development is required to develop this system. The fact that such a system has not already been built can be attributed to the lack of unified effort and economic incentive to develop such an integrated system.

Several very sophisticated system concepts appear capable of reducing flushing to the 2% to 5% range. Development of such a system would only be possible under an "unlimited funding" approach with the evaluation of alternatives, development of new technology and design and development of prototype for field testing requiring a minimum of five years. While this type of accuracy is not needed at present, future needs and increased concern over maximum energy production may require that a very sophisticated coring system be developed.

PHASE 1 SYSTEM

A Phase 1 True Fluid Coring System capable of significantly improved results over currently available systems is feasible. This system (Figure 2) would cut and recover a core maintained under bottomhole pressure but not temperature, and would rely on the freezing technique to permit handling and transportation of the core to the analysis laboratory without pressure maintenance. The system would have the alternative capability of being manufactured to take a very short (e.g., 5 foot) core which could be maintained under pressure at the surface for special applications such as the tight gas sands where freezing might be detrimental to accurate analysis. Specific design parameters considered essential to this Phase 1 system are described below.

1) Inner tube system sealed at both top and bottom by hydraulically actuated ball valves (Figure 3).

2) Lower ball valve mounted in an outer tube sub to permit maximum core size.

3) A sliding intermediate sleeve to provide a sealed chamber between the lower end of the inner tube and the ball valve sub.

4) A bypass or dump valve provision to permit bypassing most of the drilling fluid without circulating through the bit.

5) A coring bit with a tapered crown to direct dynamic fluid invasion away from the core, and a replaceable pilot bit to provide further isolation of the core from the drilling fluid (Figure 4).

6) A sleeve between the core bit and the lower end of the inner tube to provide complete isolation of the core from the drilling fluid at that point (Figure 4).

7) A viscous, non-invading, non-freezing gel inside the inner tube to be displaced by the core as it enters the inner tube (Figure 5).

8) Flow channels to allow the extruded gel to clean the pilot of the coring head.

9) Sensors to detect and provide surface indication in the case of critical operational failure.

ADVANCED SYSTEM

A highly sophisticated true fluid coring system can be built if adequate time and funds are provided. The practical value or even the necessity for such a system is dependent on the outcome of field trials of a Phase 1 system. For example, a Phase 2 system may be necessary to overcome the problem of fluid invasion during the actual coring operation. On the other hand, if bit design, fluid bypassing, and other concepts in the Phase 1 system substantially eliminate this invasion problem, the necessity for a Phase 2 system is not as great.

Since an advanced true fluid coring system is envisioned essentially for the purpose of solving the invasion problem, any Phase 2 system must address this problem first. Such system might include:

1) A core barrel run below a packer to isolate the reservoir rock from the conventional drilling fluid (Figure 6).

2) A closed circulating system below the packer utilizing a special non-invading circulating fluid with the pressure of this fluid being balanced to match reservoir pore pressure, thus eliminating hydrostatic overpressures (Figure 6).

3) The conventional fluid circulation above the packer maintained to

condition the hole and to drive a mud motor providing hydraulic, mechanical and electrical power for operation of servo-controls and sensors in the coring system (Figure 7).

4) Rotary power provided by the drillstring from the surface or by a mud motor or an electrodrill (in which case, there would be direct communications with the surface and the need for downhole power generation would be eliminated).

Several interesting alternative concepts have been proposed for handling the core and analysis. In one alternative, the core barrel would consist of a pressure coring system capable of maintaining pressure and temperature during the trip to the surface. Since the pressure and temperature conditions must be maintained at least through some point in the analysis cycle, it is probable there would be provision for on-site analysis in order to minimize the problems associated with maintaining pressure and temperature. The pressure coring system would very likely be an evolutionary design based on Phase 1 experiences.

In another approach, logging sensors would measure reservoir properties as the core passes through the lower end of the inner tube (Figure 8). The coring system could be designed with or without pressure and temperature maintenance capabilities as required. With advances in logging techniques, this approach may supercede the other more normal coring schemes since accurate property measurement downhole would eliminate pressure maintenance and surface handling problems that greatly complicate the system design.

CONCLUSIONS

1. A practical system for obtaining more accurate fluid saturations is feasible.

2. The best first-stage approach is a fairly uncomplicated pressure core barrel.

3. Two very sophisticated "advanced" systems for greatest accuracy in results appear feasible given "unlimited" development resources.

4. One "advanced" concept is based on a highly complicated pressure core barrel.

5. Another "advanced" system involves examination of core at the bottom of the hole using logging techniques.

6. Regardless of technique, the major problem to be overcome is that of cutting the core without disturbing the true fluid content.

7. Areas requiring additional study include:
   - the influence of bit design on fluid invasion; and
   - identification of drilling fluids additives to improve non-invading properties.

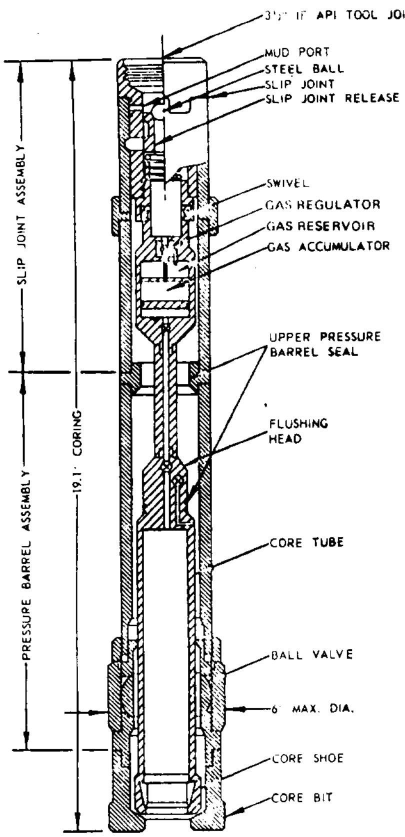


Figure 1
Loomis pressure core barrel.

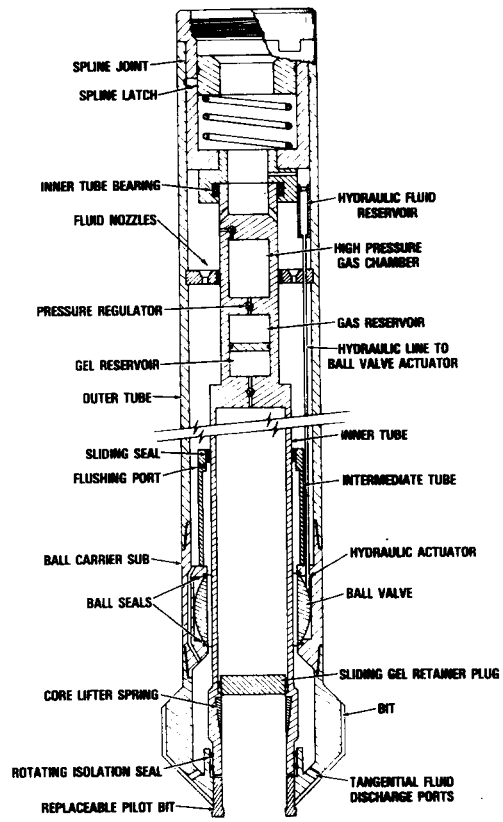


Figure 2
PHASE I PRESSURE CORING SYSTEM

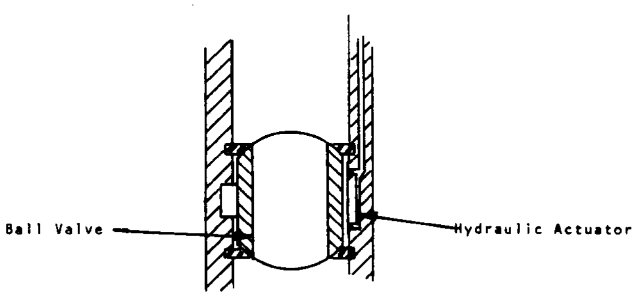
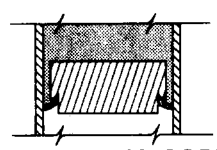


Figure 3
Hydraulically actuated ball valve.



PLUG PRIOR TO CORING
PREVENTS LOSS OF GEL

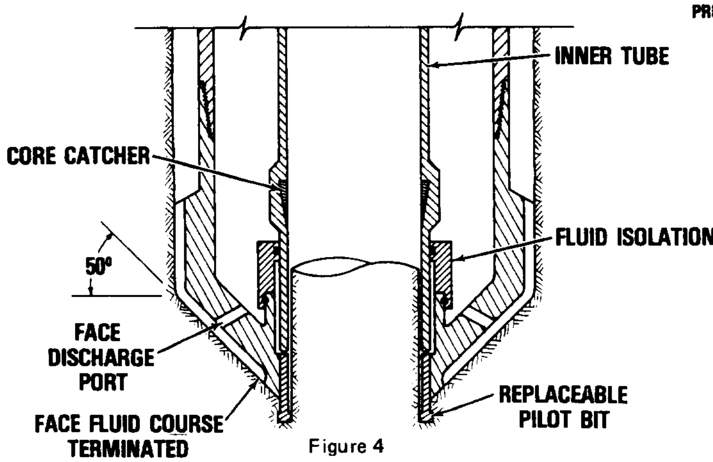


Figure 4
Tapered crown coring bit with replaceable pilot.

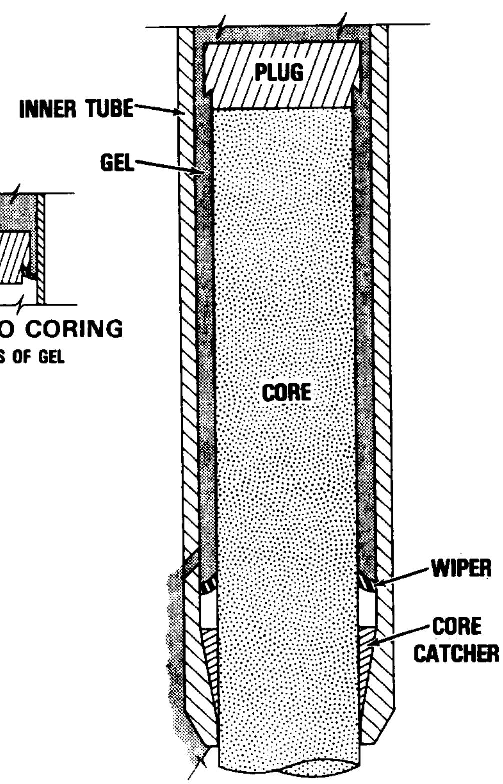


Figure 5
Non-invading, non-freezing Gel inside inner tube.

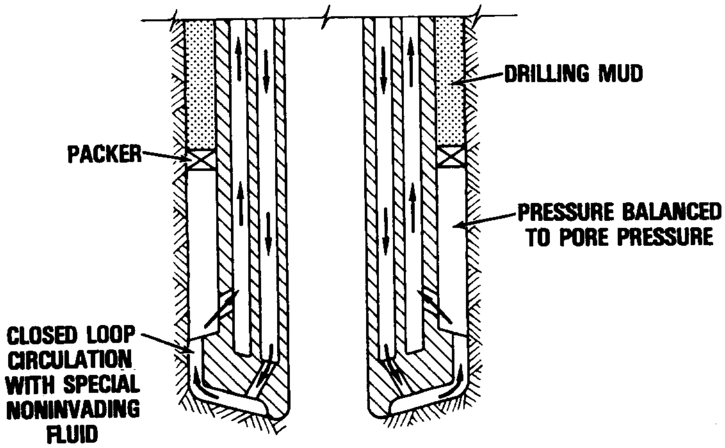


Figure 6
Packer isolation of closed loop drilling fluid system.

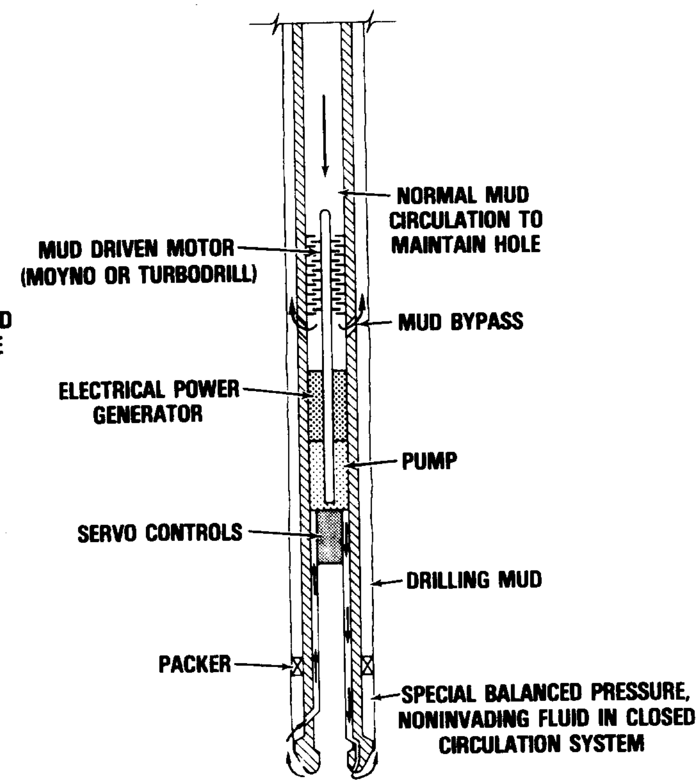


Figure 7
Phase 2 coring system.

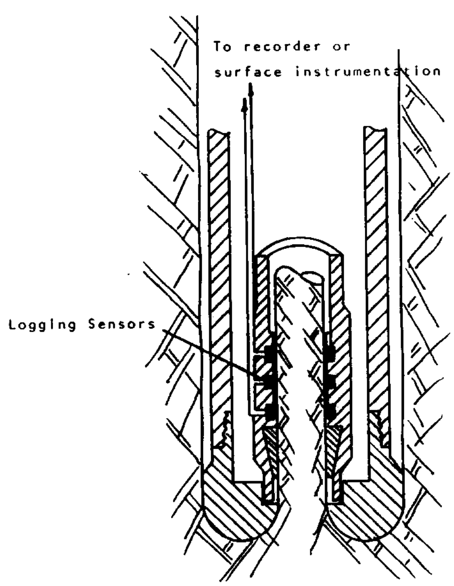


Figure 8
Logging while coring tool.

TABLE 1

APPLICATIONS OF TRUE FLUID CORE ANALYSIS DATA

PARAMETER MEASURED	APPLICATION
NEW RESERVOIRS	
Initial fluid saturations Porosity Formation resistivity factors Acoustic velocity	Improved reserve estimates and better evaluation of logs on later wells
Relative permeability Relative wettability Flow tests	Planning for future secondary and tertiary recovery
OLD RESERVOIRS	
Present fluid saturations Porosity	Evaluation of secondary and tertiary recovery economics
Relative permeability Relative wettability Flow tests	Selection and planning of recovery programs

SANDIA LABORATORIES
DRILLING TECHNOLOGY RESEARCH PROGRAM
ALBUQUERQUE, NEW MEXICO

by

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ABSTRACT

This paper presents the activities of the Drilling Technology Research Program conducted by Sandia Laboratories for DOGST/ERDA from program inception in April, 1976, to September, 1977. Progress on four projects is presented -- High Performance Bits, High Temperature Mud Instrumentation, High Temperature Materials and Downhole Information While Drilling.

The high performance bit development centers on improved bonding techniques for attaching the General Electric man-made diamond (Stratapax) to a mounting structure or bit body. Bond strengths in excess of 80,000 psi (550 MPa) in shear have been produced by diffusion bonding. The improved bonding technology will accelerate application of the Stratapax to drill bits by improving manufacturability and reliability of these bits. Single point cutting tests of diffusion bonded Stratapax are discussed along with plans for bits to field test the diffusion bonds.

Preliminary design work on high temperature mud filtration and viscosity instrumentation is described along with initial attempts to characterize physical changes that occur in muds in deep hot wells. The goal is to develop tests that will simulate downhole conditions. This field equipment will allow on-site evaluation which will decrease mud costs by reducing the necessity of over treatment of drilling fluids. Experiments underway to determine ways to increase the service life of drill steels and elastomers in hot corrosive environments are discussed. Better service life will decrease the number of equipment failures, reduce expensive fishing jobs and allow completion of more wells in hostile environments. A fourth area, Downhole Information While Drilling, has limited activity on development of a "Drilling and Formation Information System" to determine the difference between formation and mud column pressures while drilling. These programs will aid in reaching the ERDA/FE goals by improving rig efficiency, reducing drilling costs and increasing the footage drilled per year. Additional footage will yield increased petroleum reserves.

Prepared for the Energy Research and Development Administration, under Contract No. (29-1)-789.

SUMMARY

The Drilling Technology Research Program at Sandia Laboratories, being conducted for the Division of Oil, Gas and Shale Technology/ERDA, is composed of four parts -- High Performance Bit Development, High Temperature Drilling Fluids, High Temperature Materials and Downhole Information While Drilling. This document reports the activities of the program in FY-76, FY-76A and FY-77.

The primary thrust of the High Performance Bit Development Program has been the development of an improved bonding technique for attaching the General Electric Co. man-made diamond cutters, Stratapax. Diffusion bonding has been selected for development because it provides a strong attachment method at a relatively low temperature that is more resistant to weakening due to frictional heating and fluid erosion than conventional brazing. Suitable bond properties have been demonstrated in the lab. The present efforts are directed to developing a manufacturing technique and production specification for the diffusion bond using commercially available processes. Drill bits are being designed to field test the diffusion bonded joints to demonstrate the serviceability of the bond.

Accomplishments to date are:

(1) Ni-Ni diffusion bonds with shear strengths in excess of 80 ksi have been prepared. These bonds are both heat and erosion resistant and their toughness has been demonstrated in laboratory single cutter tests.

(2) Single cutter tests have shown a diamond failure mode in harder rock at currently accepted low rake angles ($\leq 15°$). Rake angles greater than 20° have been shown to minimize this failure mode and provide a controlled wear, longlife, self-sharpening cutter.

(3) An interactive graphics computer algorithm has been developed that greatly reduces the design time required to define an optimum Stratapax bit configuration.

(4) A Stratapax core bit has been developed jointly with American Coldset Corp. and has shown greatly improved drilling rates and life in laboratory tests. Further development of this bit could greatly reduce coring costs.

The High-Temperature-Pressure Mud Instrumentation work has centered on a state of the art assessment and instrumentation definition and design. This program has characterized the effects of high temperatures and pressure on drilling muds and will provide field portable test equipment to simulate downhole conditions in mud testing. Development of a high-temperature/pressure viscometer and a high temperature filteration test are underway.

The High Temperature Materials project includes testing of samples of coated elastomers and specimens of drill steels with various heat treatment to increase the service life of these materials in a high temperature, sour gas environment. Ageing tests and fatigue tests are being conducted and scheduled for completion by the end of FY-77.

In the fourth project, Downhole Information While Drilling, work was in the form of an investigation to determine areas that would benefit from ERDA support. After considerable study, it has been concluded that the technique proposed by Mobil R&D Corporation for determining the difference between the formation pressure and mud column pressure while drilling is a technique that should be actively pursued. This project is described in the joint Mobil-Sandia proposal, "Drilling and Formation Information System." The technique will be a valuable asset in drilling into pressure sensitive formations and in frontier areas and will complement the downhole telemetry systems that are being developed by industry at the present time.

In all of these projects it has been Sandia's policy to actively consult with industry in order to have the best possible information to direct our work. It is also program policy to develop cooperative programs with industry where possible to insure proper program direction and eventual utilization. These cooperative programs range from formal contractual arrangements to informal working agreements. Industry is willing to participate in these programs, especially if arrangements can be made in such a manner as to avoid compromise of their competitive position.

The following sections give a more detailed description of the work to date and some indication of the planned activities for the future.

HIGH PERFORMANCE BIT DEVELOPMENT

This project is designed to aid in development of high performance bits with the goal of higher penetration rates in deep wells and offshore where drilling costs are very high. Because of the great promise shown by the GE-Stratapax cutters in tests reported to Sandia by GE and others in the drilling industry, it was decided to direct the full efforts of this program toward aiding in developing Stratapax bit technology.

Early studies in the application of Stratapax to rock drilling[1] showed that one of the primary failure modes was fracture of the braze joint between the Stratapax and supporting stud. Low temperature brazes have been used due to inherent temperature limitations in the man-made diamond. It was decided that Sandia could best help accelerate the use of Stratapax in drill bits by improving the bonding techniques used. A necessary part of this program is to evaluate the integrity of the bond in field drilling applications. This requires extensive testing of the bond including design of a bit for field testing as a final proof test for the bonding technique. It is under these guidelines that the activities described below were conducted.

The results to date include the development of an Ni-Ni diffusion bond that in initial tests shows the high shear strength, erosion resistance and thermal stability desired. In baseline braze testing on single cutter tests, there was evidence of braze softening due to friction heating of a worn cutter. The new technique uses an Ni-Ni bond which will not soften at these temperatures. Single cutter tests in hard rock have also demonstrated the importance of high negative rake angles (greater than - 20°) for cutting edge stability and long life. Early design layouts of the test bit demonstrated the need for automated technique for positioning the Stratapax on the bit body. An interactive graphics computer algorithm is being developed to position the Stratapax in an optimum way. These results are described in more detail below.

The present plans for the program include additional manufacturing development of the bonding technique and construction of several bits to test the improved bonds. The impact and fatigue resistance of the bonding technique must be evaluated in full scale field tests. The baseline rock cutting studies gave some indication of the ruggedness of the bond but only a field test can give the ultimate proof of field worthiness. Future bonding studies will be directed towards insuring consistency and manufacturability. The design of the test bits in cooperation with bit companies are proceeding with the critical area of bit hydraulics requiring considerable effort.

Stratapax Bonding Study

The objective of Sandia's Stratapax bonding studies is to develop a joining technology for Stratapax cutters which will assure joint efficiencies adequate for all high performance bit designs. Since high drilling rates create large forces and significant heating, the development of high strength joints to Stratapax cutters is important to high performance bit development.

Conventionally, Stratapax cutters are joined to cermet studs or drill bodies by brazing with an Ag-Cu-Zn-Cd alloy. Typical strengths of these braze joints are reported to be $\sim$ 35,000 psi. Some variation in joint strength can be expected due to flux inclusions. These joints have often failed in field tests.

Several alternate approaches to improving joint efficiencies have been considered. These include improved braze techniques, ultrasonic welding, friction welding, diffusion bonding, and diffusion brazing. Braze joints could probably be made more consistent in strength by minimizing or eliminating flux entrapment, but the ultimate strength of braze joints can probably not be made to exceed 50,000 psi in shear, because of the necessity to use alloys which flow well at 650°C and the braze is subject to softening due to the heat generated while cutting.

Advantages of diffusion bonding are the ability to bond to complex shapes, maintain thin bond zones and potentially produce very high joint efficiencies. Potential disadvantages of diffusion bonding are the probable need to metallize parts prior to bonding, high capital equipment costs and the fact that required bonding temperatures are near the maximum permissible limit of the Stratapax (650-700°C). Diffusion bonding was selected for development as an alternate process to brazing because of potentially high joint efficiencies obtainable by proven process techniques.

Nickel and cobalt were selected for investigation as platings on the tungsten carbide-cobalt matrix cermets to increase the bondable areal fraction. Cobalt was an obvious choice because of its demonstrated ability to bond to tungsten carbide. Nickel was attractive from several points of view. First, of the f.c.c. metals, which have generally shown better bonding than b.c.c. and h.c.p. metals, nickel is the strongest. Another favorable property of nickel is the ease with which organize barriers can be removed. Also, nickel has the ability to destroy organic surface contaminants and oxide films by absorption during diffusion bonding.

Experimental Approaches

Metallization -- Platings applied to cermet surfaces prior to diffusion bonding must not only be bondable but must exhibit strong interfacial bonds at the cermet surfaces. Two plating processes have been satisfactorily evaluated: electroplating and a physical deposition technique, d.c. electron beam ion plating.

In the electron beam ion plating process, the cermet parts are initially sputter cleaned with argon ions. While d.c. sputtering is still in progress, electron beam evaporation is initiated so as to result in ion implantation of metal ions for approximately the first 100 Å of deposit. Then sputtering is discontinued and deposition continues resulting from electron beam evaporation. Because of the initial sputter cleaning, this process is expected to produce a high purity cermet-plating interface. Also, the process produces high purity depositions with clean, active surfaces.

Bonding -- Initially, diffusion bonding studies were performed by uniaxially loading pairs of tungsten carbide cermets in a vacuum hot press. The specimen chamber was evacuated to maintain a pressure of $\sim 10^{-6}$ torr at bonding temperatures. A disadvantage of uniaxial loading is that mechanical restraint, both geometrical and frictional, produce pressure hill effects and non-plastic zones near the faying interface which are known to cause non-uniform bonding. In an effort to minimize the effect of these phenomena, most of the specimens were bonded at an average compressive stress of 100,000 psi, which is an order of magnitude greater than the flow stress of either nickel or cobalt, in the 600-650°C temperature range. A second problem with uniaxial bonding is that pressure gradients can easily develop transverse to the loading axis unless all specimens are accurately aligned and surfaces are parallel.

A more sure approach of avoiding pressure gradients is to diffusion bond under isostatic pressure. In this study specimens were gas-pressure bonded to evaluate this approach. Gas pressure bonding greatly simplifies loading, since parts of irregular shape can easily be uniformly loaded so long as their faying surfaces are parallel and external surfaces are loaded with a suitable pressure medium. Two gas-pressure bonding experiments have been conducted at Battelle Memorial Institute, Columbus, Ohio, with specimens prepared by Sandia. In the first experiment, one group of specimens was bonded at 600°C, whereas the other was bonded at 650°C. All specimens were isostatically bonded at a pressure of 40,000 psi (275 MPa). The specimens were encapsulated in a pressure medium of CS graphite, which was canned in thin walled (0.035 inch), 304 stainless steel tubing. The tubes were sealed by electron beam welding stainless steel end caps to the open end while the assemblies were under a vacuum of 10^{-5} torr. Prior to assembly, the graphite and stainless steel parts were vacuum outgassed one-half hour at 1150°C.

In the second experiment, one run was made at 30,000 psi (206 MPa) and 650°C and a second run at 40,000 psi (276 MPa) and 650°C. A core bit was included in the lower pressure run. The canning procedures were similar to those used in the first experiment, but 0.065 in stainless steel cans were used.

Results of Initial Bonding Experiments

Objectives during this initial phase of the Stratapax bonding study were:

(1) to determine the feasibility of joining tungsten carbide cermets by diffusion bonding

(2) to evaluate materials and processes for metallization of cermets in preparation for diffusion bonding,

(3) to evaluate gas-pressure bonding as a process for diffusion bonding of cermets, and

(4) to bond a set of Stratapax to a full bit blank.

Most of the study employed tungsten carbide-cobalt cermet blanks, which were metallized, diffusion bonded, and then shear tested to failure. One blank of each pair had cobalt enriched surfaces to simulate cermet studs with cobalt enriched surfaces, whereas the other had the normal non-enriched surface of the Stratapax. The first experimental results are summarized in Table I. The ADH series of specimens were all bonded by uniaxial loading, whereas the GPB series were gas-pressure bonded.

Advanced Experiments

Additional experimental studies are being conducted to develop techniques for bonding Stratapax directly to drill bodies, study the cermet plating interfaces and explore the practicality of gas-pressure bonding as a production process.

Drill bits are expected to utilize Stratapax cutters in two ways: mounted on cermet studs and bonded directly to drill bodies. Results of recent gas-pressure bonding studies indicate that Stratapax cutters can be bonded to cermet studs by techniques already developed. However, direct bonding to drill bodies introduces new problems involving materials, size and complexity in shape. These problems suggest the use of powdered materials as pressure transfer mediums versus the commonly used machined inserts. This technique is being studied in a series of experiments, the first of which is described below.

Experiments with Powdered Pressure Transfer Mediums

A second series of cermet specimens has been gas pressure bonded at Battelle Memorial Institute, Columbus, Ohio. The objectives of these studies were to evaluate:

(1) The dependence on bonding pressure (207 MPa vs 276 MPa),
(2) The effect of metallization thickness (60 μm nickel vs 25 μm nickel),
(3) Gas-pressure transfer medium (graphite granules and spherical aluminum powders), and
(4) Encapsulation techniques for coring bits.

Following bonding at 650°C for four hours, the encapsulation cans were removed from the autoclave. Visual inspection of both the cans and the specimens extracted from the cans indicated that sufficient compaction of the pressure transfer medium had occurred, with the possible exception of the can containing the coring bit. To recover the specimens, the graphite granules were easily poured from the cans. As expected, the aluminum was fully densified and required dissolution in potassium hydroxide (20%)/water solution.

The bonding of the Stratapax cutters to the coring bit was unsuccessful. The welds were very intermittant and the Stratapax were easily removed with moderate hammer blows. The faying surfaces did not appear to have been brought into continuous intimate contact. The most probable cause of this failure is insufficient compaction of the pressure transfer medium (graphite granules). The can collapsed radially, but underwent very little reduction in the axial direction, presumably due to column strength. In spite of the failure to achieve good weld joints, several design concepts were proven in this experiment. The can was designed to pressurize the coring bit both internally and externally to minimize distortion. Also, molybdenum-stainless steel fixtures which were designed to hold the Stratapax in place during bonding appear to have functioned well and were easily removed.

Approximately half of the samples from the recent gas-pressure bonding experiment will have been shear tested by July 15, 1977. The shear test data are summarized in Table II. These data indicate the graphite granules can be substituted for solid machined graphite as a pressure transfer medium. However, as was demonstrated in the case of the coring bit, the use of graphite granules requires careful design of the assembly to produce full compaction of the pressure transfer medium. A pressure transfer medium which is highly plastic at bonding temperatures, such as aluminum or glass, should accommodate a wider range of assembly designs. Although in the first such experiment, high strength bonds were not achieved in the three samples made with aluminum as the pressure transfer medium. Further analysis of these samples has been initiated to determine the cause of the low strength failures.

Decreasing the bonding pressure only had a slight effect on shear strength. It is anticipated that an increase in bonding temperature to 973 K from 923 K will more than offset the decrease in bonding pressure. Autoclaves large enough to accommodate most drill bits restrict bonding pressures to a maximum of 207 MPa.

The shear strengths show little dependence on plating thickness. The thicker plating (60 μm) is expected to be more tolerant to surface waviness.

Copper matrix cermet samples were included in this experiment for the first time. In all cases, the shear test samples failed in the copper matrix cermet rather than in the weld zone.

The strength of diffusion bonded cermet couples has been limited by the quality of the cermet-plating interface. Studies of the interface by scanning electron microscopy has yielded structural information about the interface and metallization. These studies have been initially applied to electron beam ion plating since it has yielded the highest strength bonds. Effects of plating variables such as reactive gasses vs inert gasses for sputter cleaning, r.f. vs d.c. sputtering, and cobalt vs nickel are being evaluated. Also, various substrate conditions are to be studied, including the effect of cobalt enrichment and metallizing directly to ground cermet surfaces.

Although electron beam ion plating has demonstrated the potential for producing high strength bonds, the process must be scaled up to complex commercial size bits. Plans are underway to contract with two commercial suppliers to develop the capability of metallization by electron beam ion plating on a large scale. This development will include the capability of metallizing complete bits with complex geometries. A contract is also being negotiated to develop a supplier to prepare CVD nickel samples since this technique offers several advantages.

Test Bit Design

A program has been initiated to develop a high performance drill bit to field test the improved Stratapax bond.

The Stratapax cutter is composed of a circular carbide substrate faced with man-made diamonds in a layer .020 inches thick. The Stratapax are manufactured in two sizes: 1) .32 inch diameter and 2) .52 inch diameter. The diamond surface is smooth, extremely hard, and has been used commercially to machine ceramics, graphite structure and similar abrasive materials.

The manufacturer, General Electric (G.E.) has a program to evaluate the performance of the Stratapax in well drilling. G.E. has accumulated extensive data both in the laboratory (Tulsa University) and in drilling operations in various parts of the country.

A program to supplement the G.E. data was established in Sandia's model shop to determine the effect of rake angle on life and the forces involved in rock cutting. An instrumented cutter bar was designed which would hold the Stratapax securely at different rake angles and would yield three axis dynamic force data in a variety of geologic samples.

In the tests, large rock samples were mounted on the table of the King mill. These test rocks were rotated at speeds that result in surface cutting speeds of 120' per minute. Cuts of various depths and feeds were made in St. Cloud Gray Granodiorite (41,000 psi compressive strength), White Sierra Granite (28,000 psi compressive), and Texas Pink Granite (23,000 psi compressive). The hard rocks were used because they give accelerated wear and fatigue data. During the initial tests, which were performed using the cutters with the manufactured rake angle of 5° negative, a cutter failed and the carbide stud holding the cutter sheared. Investigation indicated the failure probably occurred in stages, that is, the diamond surface failed causing the cutting forces to rise. The higher forces then caused the mounting stud to fail.

To pursue this possible problem, a series of tests were performed at shallow penetration rates (.040 inch). The failure of the diamond surface was again observed, but the test was halted before the supporting stud failed. Analysis of the data and inspection of the damaged Stratapax resulted in the conclusion that the diamond face had failed in shear due to high vertical forces on the diamond surface. By increasing the negative rake angle, it was possible to determine that in hard-strong rocks rake angles less than 20° often result in catastrophic failure of the diamond and at angles greater than 20° the diamond surface and supporting carbide substrate were instead slowly worn away, resulting in a self-sharpening action.

The wearing process and cutting action results in the generation of heat in the cutting element and carbide stud. The heat generated is enough to soften the current braze joint which holds the Stratapax to the mounting stud. Field tests by G.E. have also noted a tendency for the drilling mud to erode the braze joint. The efforts of this program are directed towards improving the strength and temperature capability of the joint.

A second series of tests in sandstone (6,000 psi compressive) and limestone (8,000 psi compressive) were performed. These soft rocks did not have sufficient strength to fracture the diamond face or noticeably wear the Stratapax in the test setup. Other rock samples of dolomites, shales, etc., will be obtained to increase the knowledge of Stratapax cutting characteristics in sedimentary rocks as funds are available. A report covering these studies will be issued.

In parallel with the physical testing of the Stratapax, a design program was initiated to adapt the Stratapax to a field test drill bit. Two designs are being investigated: A Stratapax roller-cone hybrid and an all-Stratapax bit. These designs have been completed. During the initial layout of the drill bits, it became evident that the drafting procedures used to position the Stratapax cutters to give full bottomhole coverage and equal cutter loading was at best an estimate. The time involved was extensive and the design required evaluation of each cutter's loading with drawing layouts, digitizers or planimeters.

To minimize the effort required and increase the design accuracy, Dr. K. W. Chase, Brigham Young University, was assigned the task of developing a computer program to calculate the cutting area, volume removed, wear surface, and radii to give equal volume or wear surface per cutter per revolution of the drill bit.

The resulting graphics program will optimize the location of the individual cutters. The initial program was applied to the drill bit designs and quickly calculated the positions of the individual cutters using a criteria of equal volume removed per cutter. With further effort the program can be generalized to evaluate and optimize other drill bit designs for the industry. This program can also be expanded to evaluate the effect of cutter wear, rake and cant angles and torque on the drill bit.

One of the most significant problems remaining in Stratapax bit technology is bit hydraulics. While this problem is not unique to Stratapax designs, the fluid flow required in cleaning the bit and hole bottom are more stringent in Stratapax bits. Poor bit cleaning has apparently been a problem in virtually every Stratapax bit tested to date. Sandia will devote considerable effort to this problem in our field test bit designs. Plans are being made to enter into cooperative ventures with several bit companies to build the test bits. These bits will be manufactured and tested as funding and scheduling permits.

Slim-Hole Coring Bit

In order to obtain field test data at minimum cost, a coring bit design concept was conceived which would incorporate the emerging technology of the Stratapax cutters with the conventional technology of a diamond core bit. The size selected was a "NQ" bit size (2.98" OD x 1.875" ID). The concept was presented to American Coldset Corporation and they joined Sandia in a no-cost, cooperative bit development program.

Three prototype core bits were made with American Coldset Corporation (ACC) who built the bit blank with diamond pads. Sandia purchased the Stratapax and mounted them on the first bit using conventional brazing techniques. The bit was then tested on September 25, 1976. The results are shown in Table III. In mounting the Stratapax to the bit, one of the braze bonds was visibly defective. It failed while drilling along with another braze that was probably defective, but neither failure was detected on the drilling records. The bit continued to drill until drilling location had to be changed on the Sierra White Granite specimen. The bit and the Stratapax were not damaged as a result of the loss. A conventional diamond coring bit was run in this rock as a comparison standard. Penetration rates as high as 30 ft/hr were noted at the start, but within 70 inches of drilling in this rock the rate of the conventional bit decreased to 3 ft/hr and the bit was visibly worn. The Sandia-ACC design drilled approximately 24 inches with no apparent wear.

A second bit was included in the last bonding experiment. The bonding was not successful due to canning problems but the bit dimensions remained stable. The bit will be remetallized and bonded in a later experiment.

HIGH TEMPERATURE MUD INSTRUMENTATION

The goal of this project is to develop field test equipment for drilling muds that will simulate the high temperatures and pressures found in deep wells. This technology is needed to allow determination of mud performance at depth at the well site while drilling. Presently, this information is unavailable at the well site and overtreatment with chemicals is practiced to reduce the mud problems experienced. This procedure is costly and does not assure elimination of the problem. The project is divided into three parts -- modification of existing equipment, new equipment design where modifications are not feasible, and determination of the high temperature-pressure mud characteristics that need to be considered. This latter effort will be conducted by consultation with industry plus laboratory investigations at Sandia and Maurer Engineering Inc. (MEI), sub-contractor on this program.

The modification of existing equipment is being conducted at MEI. Their efforts involve developing a high temperature filteration test and modification of the Fann 50C laboratory viscometer for field portable use.

Filter papers used in present tests char well below the desired 500°F in the mud filtration tests. MEI has been testing other porous media that will give repeatable results. Several materials have been identified that perform well up to the desired temperatures. These materials include metal felts, sand with a plastic binder and high temperature cloths.

After the best candidate material is selected, a test standard will be prepared and submitted to the API for inclusion as a standard filteration test.

The Fann 50C is a laboratory viscometer capable of testing the viscosity of muds at temperature and pressure. The test cell from this device is being used in development of a field portable viscometer capable of determining viscosities of mud up to 550°F and 1,500 psi.

Sandia is designing a viscometer capable of determining the viscosity of drilling muds up to 550°F and 20,000 psi. This device will be fully field portable. The device is a rotating viscometer driven by a magnetic torque coupler. Viscosity can be measured through the full range of shear rate with a variable speed motor. The design is simple and allows for easy maintenance.

HIGH TEMPERATURE MATERIALS

This project is designed to improve the service life of commercially available materials. The program is currently divided into environmentally resistant elastomer and corrosion-fatigue resistant steel investigations with each program described below. It should be noted that neither project has the goal of developing an entirely new material but rather to upgrade the service capabilities of existing commercial materials. Experiments are presently underway and because of the extended environmental exposure time required for each test, definitive results on some of the tests are not available at this time.

Environmentally Resistant Elastomers

Elastomers are widely used in drilling and production equipment, and many of the commercially available elastomers fail under the severe environmental conditions that prevail in deep oil and gas wells. There is, therefore, a need for elastomers which will survive at elevated temperatures in the presence of sour-gas, steam, drilling mud, and oil or any combination of these conditions. Although Kalrez, a perfluoroelastomer developed by DuPont has shown excellent promise because of its outstanding chemical and thermal resistance, this material has found only limited application because of its high cost. The goal of this program is to overcome this cost problem by enhancing the chemical resistance of less expensive elastomers. Enhanced chemical resistance can be realized by plasma polymerization in which a very thin layer of an impervious film is deposited on the rubber surface or by adding stabilizing compounds to the elastomers. Improved chemical resistance can be accomplished either by applying an inert coating to the elastomer or by modifying the surface of the elastomer in such a way as to enhance its stability.

Plasma deposited films are noted for their chemical inertness, and strong adhesion to the substrate if the film is sufficiently thin. Such films are generally highly crosslinked and therefore should exhibit reduced permeability to gases. Plasma polymerizations will be carried out in an inductively coupled RF glow discharge apparatus. Although Teflon and Parylene coatings have been used to environmentally protect metals and electronic circuitry for some time, these coatings have never been used to protect elastomers. The C-F bond is one of the strongest chemical bonds and accounts for the high stability of such polymers as Teflon and Kalrez. In theory then, enhanced stability could be achieved by fluorinating the surface of polymers such as Viton or EPR, whereby C-H bonds are converted to C-F bonds. The primary purpose of this part of the study is to determine the feasibility of these two approaches toward stability enhancement. Currently, the rubber industry is not active in this area. Although this technique is developmental in nature, it has been used successfully in a number of other applications at Sandia.

To date, it has been found that Teflon coated Vitons were slightly more resistant to attack by sour gas at 200°C than uncoated Viton specimens. That only marginal enhancement of stability was achieved was attributed to the fact that the conditions and apparatus for making high molecular weight, crosslinked Teflon via plasma polymerization were not optimum. The RF glow discharge apparatus is being modified in an effort to overcome this problem. Success was experienced however, in coating Viton, EPR and other elastomers with a tough, high quality film of Parylene C (poly (chloro-p-xylylene)). Tests to evaluate the effectiveness of this coating as a barrier for sour gas are in progress. Initial efforts to fluorinate Viton using C_2F_6 in an electrical discharge look promising. Qualitative observations suggest such that enhanced resistance to sour gas was realized. Tests to quantitatively confirm these findings are underway.

In the coating tests, samples of Buena N, Viton and Kalrez are coated and the efficiency of these coatings is evaluated as follows: 1) dynamic mechanical properties, i.e., shear modulus, of both the coated and uncoated rubber specimens will be determined before and after exposure to sour gas at elevated temperatures; and 2) stress relaxation experiments will be performed under the same conditions. If improved stability is observed in these tests, the samples are exposed to an environment which approximates that encountered in a deep oil well, i.e., the effect of high pressures, steam and drilling muds will be determined.

Another approach to enhancing the resistance of elastomers to a sour gas/steam environment is to incorporate additives that are reactive toward these chemicals. The additives we propose to evaluate will be polymeric in nature so as to minimize their loss due to volatilization. The test methods employed will be similar to those described above. New formulations will be made from both Viton and Kalrez gumstocks.

A Hastelloy C Autoclave has been ordered so as to be able to evaluate elastomers under conditions that approximate those found in a deep oil well. In addition, a microrubber mill was ordered. This mill will be used to incorporate stabilizing additives in such rubber resins as Kalrez, Viton and EPR.

Corrosion-Fatigue Resistant Steels

Fatigue failure of drill stem is a problem that has plagued the drilling industry for decades. The object of this program is to determine whether this type of failure can be minimized by closer control of drill stem manufacturing procedures.

The American Petroleum Institute specifications for drill stem are written primarily in terms of mechanical properties and say very little about manufacturing processes. As a result, most grades of drill stem can be and are processed in a variety of ways. Little is known about the effects of these processing variables on fatigue behavior. It is well known that processing variables can significantly influence properties such as toughness and environmental embrittlement wear when less sensitive variables such as hardness are unchanged. This program will determine to what extent the method of heat treatment influences fatigue behavior in drill stem materials. Special attention will be given to fatigue in H_2S containing environments because of the increased severity of the problem in sour gas holes.

The material selected for initial study is 4140 steel. This material was selected because it is similar to drill stem steels and because yield strength levels corresponding to those of intermediate strength drill stem steels can be easily obtained by two widely different heat treatments: normalizing and quenching and tempering. Initial experiments focused on determining the details of the heat treatments required to give the desired strengths. It was found that a yield strength of 96 ksi (662 MPa) could be obtained by normalization (relatively slow cooling from 1600°F) or by water quenching from 1550°F followed by tempering at 1200°F for 24 hours. Fatigue specimen blanks were given these heat treatments and machined into compact tension type specimens. The first set of fatigue tests were run in air on a closed loop testing machine. The load amplitude was measured by an electric load cell and crack length was determined by comparing the compliance of the specimen with those of standard specimens of known crack lengths. Results show that fatigue behavior in air was not influenced by the difference in heat treatment. Similar results were found when the test samples were subject to a brine environment. It is not expected that this trend will follow through the more severe simulated downhole environments, particularly those containing H_2S. These tests will be conducted in August of 1977.

DOWNHOLE INFORMATION WHILE DRILLING

This phase of the Drilling Technology Program was budgeted in FY-76 to determine areas where Sandia could assist in development of downhole sensing and telemetry system development. Several areas were identified but the most promising is a program suggested by Mobil Research and Development Corporation. This led to a joint proposal between Sandia and Mobil submitted to DOGST/ERDA which is described below. Effort in FY-77 has been limited to familiarization, coordination with Mobil and program planning by personnel that will be involved in the project.

The objective of this project is to conduct research on actual drilling wells to develop knowledge about the drilling process so that one can accurately estimate the difference between the formation and mud column pressure, called differential pressure (ΔP). This work is presently in the proposal stage, but Mobil has actively pursued the project independently for several years. The techniques and knowledge gained from this work will result in more economical (higher rate of penetration), and safer (improved knowledge of pressures, especially in geopressured zones) drilling in offshore and other frontier areas. In addition, there will be fewer bypassed hydrocarbon formations and higher well production rates resulting from decreased formation damage by the drilling fluids. Lost wells, and well disasters and delays, will be reduced since geopressured zones will be detected before they create difficulties in drilling.

The primary goal of this program is to develop a technique capable of predicting drilling differential pressures ($\Delta P = P_{mud} - P_{pore}$) to within a standard deviation of 100 psi in real time while drilling. It is known that ΔP strongly influences the drilling rate of penetration and safety aspects of the drilling operation, especially in offshore areas where economy and safety are of utmost importance. It is highly desirable to drill with a minimum ΔP (lower ΔP results in higher rate of penetration and reduced formation damage) consistent with the mud pressure required to maintain adequate control of formation fluids (especially in dangerous offshore and over-pressured zones). Thus, the objective of the project is to develop a technique that can be used to very accurately determine ΔP in real time while drilling so that it can be controlled closely at the value deemed necessary to drill at the most economical rate while maintaining control of the well. Mobil believes that current ΔP estimation techniques supply ΔP to an error standard deviation of 500 to 1000 psi when drilling at 10,000 feet in a known formation.

Formation properties constitute a set of independent variables which, along with drilling control variables, determine the values of dependent drilling variables. The formation properties can be classed as lithology, porosity, fluid content, pore pressure, and temperature. These properties are independent variables in drilling equations as they are beyond control while drilling. The drilling control variables include bit type and condition, rotary speed, weight on bit, drilling mud weight and other properties, and fluid system pressures along with various secondary equipment effects. The dependent variables are rate of penetration, rotary torque, and drill string vibrations with secondary properties such as hole diameter, hole straightness and chip size.

These variables can be combined to form drilling response equations which relate the dependent variables to the independent and control variables. Drilling differential pressure, ΔP, is a combination formation-drilling control variable that can be calculated from these drilling equations if the other variables and parameters in the equation are deterministic.

Since the inception of the program in January, 1975, Mobil has developed a ΔP estimation scheme as far as possible with currently available data. Additional field data must be collected with instrumentation superior to that presently in use. Because of the complexity of the field instrumentation problem, Sandia has been asked to join the project.

Mobil believes that this technique will be of significant aid to the entire oil and gas industry in the areas of drilling economics and safety. Furthermore, it is desirable for the proven technique to be marketed ultimately by industry service companies, thus making the advancement available to the entire industry. Mobil has already made a substantial research effort in the program area as exhibited by \$1/2 million expended on equipment, manpower, and research results, that they plan to contribute to the proposed project. For these reasons it is felt that a cooperative project is the proper way to develop this technique.

The improved procedures developed by this project should contribute to increased reserves (fewer lost wells in wildcat areas, fewer commercial intervals in a well hidden by formation damage), increased well production rates (reduced formation damage), and reduced drilling and completion costs (increased drilling rates, reduced rig time, reduced drilling problems and disasters, reduced formation damage resulting in reduced well stimulation costs). The benefits will be derived by implementation of the following project accomplishments within drilling operations:

(1) A greatly improved knowledge of the drilling differential pressure (ΔP) while drilling. This real time knowledge will allow additional control of the drilling process to obtain:

(a) Improved detection of pressure transition zones. This ability will reduce the chances of a blowout and loss of the hole when a geopressured zone is encountered, and of lost circulation when a low pressured zone is encountered. Drilling safety and environmental control will be improved.

(b) Improved selection of casing setting depths, especially in the pressure transition and overpressured zones. Improved casing point selection can sometimes result in one less casing string in a hole.

(c) Fewer trips, increased bit footage, increased penetration rate, and reduced drilling problems from differential sticking and sloughing shales because of the ability to drill safely with a low differential pressure (near balanced pressure drilling) and decreased open hole time.

(d) Reduced formation damage due to lower mud filtration penetration of the formation because of lowered differential pressures while drilling and decreased open hole time.

(e) Accurate near balanced pressure drilling will permit improved mud designs, e.g., higher mud filtrate loss will be acceptable.

(2) Real time logs of formation drillability (C_f), porosity (from C_f), pore pressure (P_p), drilling equation parameters, differential pressure, and rate of penetration (ROP). The C_f log is a good real time log by which to correlate formations from well to well. Real time collection of the above logs means that the drilling and formation properties of a well lost during drilling are permanently available up until the instant that the well was lost.

(3) New and greatly improved information on the drilling process in the form of improved versions of empirical drilling process equations. These equations can be used to improve drilling cost minimization algorithms, to help develop direct rig control techniques, etc.

This proposed program has been submitted to ERDA/DOGST in a joint Mobil/Sandia report, "Drilling and Formation Information System," dated October 12, 1976.

REFERENCE

1) Eaton, Brown, and Martin, J. Petroleum Tech., May 1975.

Table I

Shear Strengths of Diffusion Bonded Cermet Blank Pairs

	Bonding Process**				Metallization			Shear Strengths	
Identity	Technique	Pressure Kpsi	Pressure MPa	Temperature	Material	Thickness μm	Process	Kpsi	MPa
ADH-1	Vacuum Hot Press	100	690	∿ 625	Ni	38	Electroplate	51	350
ADH-2	Vacuum Hot Press	50	345	∿ 625	Ni	100	Electroplate	44	300
ADH-3	Vacuum Hot Press	100	690	∿ 625	Ni	38	Electroplate	25	170
ADH-4	Vacuum Hot Press	100	690	∿ 600	Ni + Co	125	Electroplate	58	400
ADH-9	Vacuum Hot Press	100	690	∿ 600	Co	38	Electroplate	--	---
ADH-6	Vacuum Hot Press	100	690	∿ 600	Ni	25	EB Ion Plated	90	620
ADH-7	Vacuum Hot Press	100	690	∿ 600	Ni	25	EB Ion Plated	74	510
ADH-12	Vacuum Hot Press	100	690	∿ 600	Ni	25	EB Ion Plated	75	520
ADH-13	Vacuum Hot Press	100	690	∿ 600	Ni	25	EB Ion Plated	113	780
ADH-10	Vacuum Hot Press	100	690	∿ 600	Co	25	EB Ion Plated	60	410
ADH-11	Vacuum Hot Press	100	690	∿ 600	Co	25	EB Ion Plated	54	370
ADH-5	Vacuum Hot Press	100	690	∿ 600	Co	10	Chemical*** Vapor Deposition	1.4	10
GPB-1	Gas Pressure Bonding	40	276	∿ 600	Ni	25	EB Ion Plated	77	530
GPB-2	Gas Pressure Bonding	40	276	∿ 600	Ni	25	EB Ion Plated	84	580
GPB-3	Gas Pressure Bonding	40	276	∿ 650	Ni	25	EB Ion Plated	78	540
GPB-4*	Gas Pressure Bonding	40	276	∿ 650	Ni	25	EB Ion Plated	19	130
GPB-5*	Gas Pressure Bonding	40	276	∿ 600	Ni	50	Electroplate	--	---
GPB-6*	Gas Pressure Bonding	40	276	∿ 600	Ni	50	Electroplate	--	---
GPB-7	Gas Pressure Bonding	40	276	∿ 650	Ni	50	Electroplate	47	320
GPB-8	Gas Pressure Bonding	40	276	∿ 650	Ni	50	Electroplate	42	290

* Assembly problems held faying surfaces apart.
** Bonding time for all specimens was four hours.
*** Temperatures used were too low for adhesion.

Table II

Summary of Shear Test Data for Diffusion Bonded Cermet Samples

Sample Type		Process Conditions[1]			
Cermet Matrix	Nickel Plating, μm	Pressure Transfer Medium	Pressure MPa	Shear Strength Kpsi	Shear Strength MPa
Cobalt	25	Solid Graphite	207	62	426[2]
Cobalt	60	Solid Graphite	207	61	421[2]
Cobalt	25	Graphite Granules	207	83	573[3]
Cobalt	60	Graphite Granules	207	64	442[3]
Cobalt	60	Aluminum	207	13	88[2]
Cobalt	25	Solid Graphite	276	67	464[2]
Cobalt	25	Graphite Granules	276	72	500[3]
Copper	60	Solid Graphite	207	55	381[2]
Copper	25	Graphite Granules	207	46	318[3]
Copper	60	Graphite Granules	207	58	398[3]

(1) All specimens bonded at 923 K for 4 hours.
(2) Average for three test specimens.
(3) Value for one test specimen, more specimens to be tested.

Table III

Bit Weight (lbs)	RPM	Torque (ft/lbs)	Mud Flow (gpm)	Pressure Drop @ Bit (psi)	Drill Rate (ft/hr)
1500	200	15	∿ 70	∿ 100	1.35
2500	200	45	66	100	6.1
3500	200	130	55	100	27.9